TABLE OF CONTENTS

VOLUME 1: APPLICATION, COMPANY EVIDENCE AND EXHIBITS

A. APPLICATION

B. COMPANY EVIDENCE **Page**

SECTION 1 INTRODUCTION

SECTION 2 CUSTOMER OPERATIONS

SECTION 5 CUSTOMER RATES **Page**

C. EXHIBITS

VOLUME 2: SUPPORTING MATERIALS

A. REPORTS

VOLUME 3: EXPERT EVIDENCE

A. EXPERT EVIDENCE

Labour Forecast
2021-2023

May 2021

Table of Contents

1.0. Background

This report contains detailed information concerning the method used by Newfoundland Power Inc. ("Newfoundland Power" or the "Company") to forecast its test year full-time equivalents ("FTEs") and labour expense. In addition, it explains the assumptions used to determine forecast vacancies.[1]

Newfoundland Power's current labour requirements tend to be consistent from year to year.[2] In managing its workforce, the Company matches overall capacity and capability with anticipated work requirements.

The method used to forecast labour requirements and FTEs for a test year reflects this basic workforce management philosophy.

2.0 Forecasting Workforce Requirements

2.1 Forecasting the Work

The starting point in forecasting Newfoundland Power's annual labour requirements is the Company's annual capital and operational work requirements.[3]

Annual capital work requirements are principally based on specific expenditures required to replace deteriorated, defective or obsolete equipment, and to serve forecast customer growth.[4]

Annual operating work requirements are principally focused on the maintenance and operation of the electrical system, response to customer enquiries, and commercial functions such as meter reading and billing.[5] These requirements tend to be stable over time. For this reason, historical expenditures, adjusted for changes in operating requirements, are the foundation for forecasting annual operating work requirements.

2.2 Workforce Options

Having determined the annual work requirements, the Company considers the amount of internal labour available to meet these requirements.

The Company's annual work requirements are met using a combination of regular employees, temporary employees and contractors. This approach permits Newfoundland Power to maintain

1 In Order No. P.U. 32 (2007), the Newfoundland and Labrador Board of Commissioners of Public Utilities (the "Board") directed Newfoundland Power to include this information as part of its next general rate application.

2 For the period of 2021 through 2023F, Newfoundland Power's workforce is forecast to increase by 0.2%, or 1.0 FTE.

3 In addition to capital and operating requirements, there are labour requirements for rechargeable and recoverable items. These items include labour associated with material handling (i.e. stores) and vehicle service centre labour costs, which are recharged as overheads on operating and capital work. It also includes customer jobbing, third-party provisioning services, and inter-affiliate labour charges.

4 These requirements are approved by the Board on a prospective basis each year through the Company's capital budget applications.

5 Annual operating work requirements also include general support functions, such as information services, human resources, and finance.

a highly skilled core workforce and reasonable flexibility to respond to variations in work requirements on a least-cost basis.

Annual capital work requirements tend to be met by a combination of the Company's internal workforce and contractors. This is partly attributable to the variable nature of these work requirements.[6] It is also consistent with the deployment of the Company's internal workforce.[7]

Annual operating work requirements tend to be met by the Company's internal workforce. This is partly attributable to stability of these work requirements on a year over year basis.[8] It is also partly attributable to the specialized nature of these work requirements.[9]

2.3 Vacancy Assumptions

In determining the internal workforce available to execute the annual capital and operating work requirements, the Company assesses its internal workforce on an FTE basis.[10]

The actual FTEs for the most recently completed year reflect the impact of all vacancies in that year. In other words, the FTEs for the most recently completed year include only the actual paid hours *worked in that year*. For this reason, the FTEs for the most recently completed year are the basis Newfoundland Power uses for forecasting FTEs.

In forecasting FTEs, Newfoundland Power will make adjustments for future years. This is done to better predict availability of the internal workforce to meet work requirements. This, in turn, permits the Company to assess its workforce options.[11]

The typical adjustments to an FTE forecast include anticipated retirements, leaves of absence, terminations and new hires.[12] These adjustments reflect the timing and salary impacts of

---

6 The specific requirements of annual capital work have different labour requirements depending on the projects involved. For example, penstock construction requires riggers and welders. However, electrical system operations have no ongoing requirement for those skilled trades. Accordingly, such work would be performed by contractors.

7 The deployment of Powerline Technicians ("PLTs") is an example of this. PLTs perform a mixture of operating and capital maintenance. In winter, Newfoundland Power's service obligations practically require it to have PLTs deployed throughout its service territory in sufficient numbers to respond to seasonal electrical system trouble. In the construction season, PLTs can be deployed to construction sites across the province, as necessary.

8 Approximately 4% of Newfoundland Power's internal workforce is temporary labour. Use of temporary labour provides operating flexibility.

9 Specialized knowledge of electrical system operations is required for a great deal of operational work and is a core competency of Newfoundland Power's workforce. This specialized knowledge is typically not required to perform much of the capital work requirements of the Company.

10 Newfoundland Power calculates FTEs based on employee hours worked divided by total working hours in a year. For approximately 39% of the workforce, the total working hours in a year are 2,080. For the remainder, the total working hours in a year are 1,950. The FTE calculation reflects only hours worked and permits a better matching of work requirements to available workforce options than forecasting positions and applying a vacancy allowance.

11 From a practical perspective, forecast FTEs will become the basis for the Company's determination of hiring requirements and contract labour requirements.

12 Leaves of absence include maternity leave, absences due to long-term disability or workplace injury, education leave and other leaves of absence approved by the Company.

workforce changes. For example, in the case of retirements, differences in salary and timing gaps or overlaps among employees entering and leaving the workforce can be incorporated into the adjustments.[13] A similar approach is used for employees commencing leaves of absence and those returning from leave.

These adjustments are fully reflected in both forecast FTEs and labour costs. The forecast FTEs are a tool to assess the *internal* workforce available to meet overall work requirements. The forecast labour costs reflect salary and timing differences associated with changes in the internal workforce.

Newfoundland Power's assessment of its internal workforce is undertaken in the context of its total forecast labour requirements. These total labour requirements are a function of forecast capital and operating work requirements.[14]

2.4 Reconciling Work and Labour

Newfoundland Power's total labour requirements for 2020 were $77.4 million. For 2021, 2022 and 2023, the total forecast labour requirements are $82.9 million, $87.1 million and $87.7 million, respectively. These requirements reflect forecast capital and operational work requirements for each year and include internal labour and contract labour.

The Company's internal labour expense for 2020 was $64.9 million. For 2021, 2022 and 2023, forecast internal labour expense is $67.8 million, $71.5 million and $71.7 million, respectively. The difference between the total forecast labour requirements and the Company's available internal labour will be addressed using contract labour.

3.0 2021 to 2023 Labour Forecasts

3.1 2021 FTEs and Internal Labour Expense

The 2021 FTEs and internal labour expense were calculated using the actual 2020 FTE results as the starting point. In 2020, the number of FTEs, based on the *actual hours worked*, was 611.5. The associated internal labour expense was $64.9 million. To account for the impact of inflation, the 2020 internal labour expense is adjusted to reflect salary increases applicable to 2021.

The 2021 labour forecast reflects an overall increase of 12.5 FTEs, primarily due to additional labour associated with new customer electrification programs, the Customer Service System ("CSS") Replacement Project and the Company's PLT Apprentice program. FTEs and internal labour expense in 2021 also include employees that worked a partial year in 2020, but are

[13] The time period between employees entering and leaving the workforce can be either negative or positive. For example, if a replacement employee arrives before a senior employee retires to avail of a training opportunity, this will increase the FTE count and labour expense. However, if there is a period of time a position remains vacant awaiting a replacement employee to enter the workforce, this will decrease the FTE count and labour expense.

[14] The loss of an employee in any year will typically result in the work being performed by temporary labour or a contractor. It is unusual that either capital or operating work would not be performed in any given year due to the loss of an employee.

anticipated to be in the workforce for a full year in 2021, partially offset by employees who left in 2020.

Schedule A presents the detailed breakdown of forecast internal labour expense and FTEs for 2021.

3.2 2022 FTEs and Internal Labour Expense

The 2022 FTEs and internal labour expense were calculated using the 2021 forecast as the starting point. To account for the impact of inflation, the 2021 internal labour expense is adjusted to reflect forecast salary increases applicable to 2022.

The 2022 test year labour forecast reflects an overall increase of 18.0 FTEs, primarily due to additional labour associated with the CSS Replacement Project.

Schedule B presents the detailed breakdown of forecast internal labour expense and FTEs for 2022.

3.3 2023 FTEs and Internal Labour Expense

The 2023 FTEs and internal labour expense were calculated using the 2022 forecast as the starting point. To account for the impact of inflation, the 2022 internal labour expense is adjusted to reflect forecast salary increases applicable to 2023.

The 2023 test year labour forecast reflects an overall decrease of 17.0 FTEs, primarily due to the conclusion of the CSS Replacement Project.

Schedule C presents the detailed breakdown of forecast internal labour expense and FTEs for 2023.

Schedule A
2021 Internal Labour Forecast

	Labour Expense ($000s)	FTEs	Notes
2020 Workforce			
Operating	33,108		1
Capital	23,510		
Rechargeable & Recoverable	8,302		
Total	**64,920**	**611.5**	2
2021 Salary Increase	**1,785**		3
Extra Work Day in 2020	**(248)**		4
Adjustments for 2021			
2021 Retirements			
Employee Retirement[15]	(1,659)	(12.4)	5
Retirement Replacement	1,324	11.0	6
2021 Leaves of Absence			
Employees Taking Leave	(810)	(7.0)	7
Employees Returning from Leave	521	4.5	8
New Hires	650	5.6	9
Partial Year Adjustments[16]	1,270	10.8	10
2021 Adjusted Workforce	**67,753**	**624.0**	11
2021 Workforce			
Operating	32,693		
Capital	26,446		
Rechargeable & Recoverable	8,614		
Total	**67,753**		12

[15] Retirement estimates are based on employees reaching age 65, or reaching age 60 with the combination of 95 years of age plus service, or have expressed interest in retiring prior to reaching this milestone.

[16] Partial year adjustments include FTE and labour adjustments necessary to account for employees who started or resumed their employment in 2021. These employees would not have accounted for full annual salaries in the 2020 labour expense, nor would they have accounted for full FTEs in 2020. These adjustments also include employees who left the Company in 2020. These employees do not account for full annual salaries in the 2021 labour expense, nor would they account for full FTEs in 2021.

Notes for Schedule A

No.	Description
1	The operating labour cost for 2020. It includes the impact of all retirements, leaves of absence, terminations and new hires experienced in 2020.
2	The 2020 FTEs are reflective of the 2020 work requirement. It reflects the impacts, including timing, of all retirements, leaves of absence, terminations, and new hires of regular and temporary employees in 2020. Total labour expense includes payroll loading.
3	The 2021 salary increase is based upon a weighted average salary increase of 2.75%.
4	In 2021, there are 261 work days versus 262 in 2020, resulting in a labour decrease of $248,000.
5	In 2021, there are 20 employees expected to retire. The 2021 labour cost reduction for retirements is $1,659,000. The 2021 reduction in FTEs of 12.4 reflects the timing of the forecast retirements.
6	Twenty of the retiring employees will be replaced in 2021, which results in a $1,324,000 labour cost increase and a 11.0 FTE increase for 2021.
7	In 2021, the Company forecasts 14 employees taking leaves of absence based on past experience and known circumstances. The 2021 labour reduction for leaves is $810,000, with a corresponding FTE reduction of 7.0.
8	In 2021, the Company forecasts 8 employees returning from leaves of absence based on past experience and known circumstances. The 2021 labour increase for employees returning from leave is $521,000, with a corresponding FTE increase of 4.5.
9	In 2021, the addition of 3 new hires for customer electrification programs, 2 new hires for the CSS Replacement Project, 4 PLT Apprentices, and 1 new Security Analyst is expected to increase FTEs by 5.6 and labour costs by $650,000.
10	The 2021 labour increase for partial year adjustments is an increase of $1,270,000, with a corresponding FTE increase of 10.8. Partial year adjustments include the impact of delayed hires in 2020 as a result of COVID-19.
11	The 2021 forecast FTE count.
12	The 2021 forecast labour cost, excluding overtime.

Schedule B
2022 Internal Labour Forecast

	Labour Expense ($000s)	FTEs	Notes
2021 Forecast Workforce			
Operating	32,693		1
Capital	26,446		
Rechargeable & Recoverable	8,614		
Total	**67,753**	**624.0**	2
2022 Salary Increase	**2,033**		3
Extra Work Day in 2021	**(260)**		4
Adjustments for 2022			
2022 Retirements			
Employee Retirement[17]	(1,218)	(9.5)	5
Retirement Replacement	781	6.5	6
2022 Leaves of Absence			
Employees Taking Leave	(835)	(7.0)	7
Employees Returning from Leave	954	8.0	8
New Hires	1,999	17.0	9
Partial Year Adjustments[18]	337	3.0	10
2022 Adjusted Workforce	**71,544**	**642.0**	11
2022 Forecast Workforce			
Operating	33,727		
Capital	29,006		
Rechargeable & Recoverable	8,811		
Total	**71,544**		12

[17] Retirement estimates are based upon employees reaching age 65, or reaching age 60 with the combination of 95 years of age plus service.

[18] Partial year adjustments include FTE and labour adjustments necessary to account for employees who started or resumed their employment in 2022. These employees would not have accounted for full annual salaries in the 2021 labour expense, nor would they have accounted for full FTEs in 2021. These adjustments also include employees who left the Company in 2021. These employees do not account for full annual salaries in the 2022 labour expense, nor would they account for full FTEs in 2022.

Notes for Schedule B

No.	Description
1	The operating labour cost for 2021. It includes the impact of all retirements, leaves of absence, terminations and new hires in 2021.
2	The 2021 forecast FTEs are reflective of the 2021 work requirement. It reflects the impacts, including timing, of all retirements, leaves of absence, terminations and new hires of regular and temporary employees in 2021. Total labour expense includes payroll loading.
3	The 2022 salary increase is based upon a weighted average salary increase of 3.00%.
4	In 2022, there are 260 work days versus 261 in 2021, resulting in a labour decrease of $260,000.
5	In 2022, there are 20 employees expected to retire. The 2022 labour cost reduction for retirements is $1,218,000. The 2022 reduction in FTEs of 9.5 reflects the timing of the forecast retirements.
6	Seventeen of the retiring employees will be replaced in 2022, which results in an $781,000 labour increase and an 6.5 FTE increase for 2022.
7	In 2022, the Company forecasts 9 employees taking leaves of absence based on past experience. The 2022 labour reduction for leaves is $835,000, with a corresponding FTE reduction of 7.0.
8	In 2022, the Company forecasts 14 employees returning from leaves of absence based on the 2021 forecast. The 2022 labour increase for employees returning from leave is $954,000, with a corresponding FTE increase of 8.0.
9	In 2022, the Company forecasts 14 additional FTEs required for the CSS Replacement Project. In addition, the Company forecasts 4 new PLT Apprentices and 1 hire for customer electrification programs. The 2022 labour increase is $1,999,000, with a corresponding FTE increase of 17.0.
10	The 2022 labour increase for partial year adjustments is $337,000, with a corresponding FTE increase of 3.0.
11	The 2022 forecast FTE count.
12	The 2022 forecast labour cost, excluding overtime.

Schedule C
2023 Internal Labour Forecast

	Labour Expense ($000s)	FTEs	Notes
2022 Forecast Workforce			
Operating	33,727		1
Capital	29,006		
Rechargeable & Recoverable	8,811		
Total	**71,544**	**642.0**	2
2023 Salary Increase	**2,039**		3
Adjustments for 2023			
2023 Retirements			
Employee Retirement[19]	(839)	(7.5)	4
Retirement Replacement	477	4.5	5
2023 Leaves of Absence			
Employees Taking Leave	(859)	(7.0)	6
Employees Returning from Leave	736	6.0	7
Terminations	(1,740)	(16.0)	8
New Hires	190	2.0	9
Partial Year Adjustments[20]	123	1.0	10
2023 Adjusted Workforce	**71,671**	**625.0**	11
2023 Forecast Workforce			
Operating	34,742		
Capital	27,972		
Rechargeable & Recoverable	8,957		
Total	**71,671**		12

19 Retirement estimates are based upon employees reaching age 65, or reaching age 60 with the combination of 95 years of age plus service.

20 Partial year adjustments include FTE and labour adjustments necessary to account for employees who started or resumed their employment in 2023. These employees would not have accounted for full annual salaries in the 2022 labour expense, nor would they have accounted for full FTEs in 2022. These adjustments also include employees who left the Company in 2022. These employees do not account for full annual salaries in the 2023 labour expense, nor would they account for full FTEs in 2023.

Notes for Schedule C

No.	Description
1	The operating labour cost for 2022. It includes the impact of all retirements, leaves of absence, terminations and new hires in 2022.
2	The 2022 forecast FTEs are reflective of the 2022 work requirement. It reflects the impacts, including timing, of all retirements, leaves of absence, terminations and new hires of regular and temporary employees in 2022. Total labour expense includes payroll loading.
3	The 2023 salary increase is based upon a weighted average salary increase of 2.85%.
4	In 2023, there are 14 employees expected to retire. The 2023 labour cost reduction for retirement is $839,000. The 2023 reduction in FTEs of 7.5 reflects the timing of the forecast retirements.
5	Thirteen of the retiring employees will be replaced in 2023, which results in an $477,000 labour increase and an 4.5 FTE increase for 2023.
6	In 2023, the Company forecasts 9 employees taking leaves of absence based on past experience. The 2023 labour reduction for leaves is $859,000, with a corresponding FTE reduction of 7.0.
7	In 2023, the Company forecasts 9 employees returning from leaves of absence based on the 2022 forecast. The 2023 labour increase for employees returning from leave is $736,000, with a corresponding FTE increase of 6.0.
8	In 2023, the Company expects an FTE reduction of 16.0 FTEs as a result of the conclusion of the CSS Replacement Project and the Instant Rebates Program. This will result in a labour reduction of $1,740,000.
9	In 2023, the Company forecasts 4 new PLT Apprentices. The 2023 labour increase for new hires is $190,000, with a corresponding FTE increase of 2.0.
10	The 2023 labour increase for partial year adjustments is $123,000, with a corresponding FTE increase of 1.0.
11	The 2023 forecast FTE count.
12	The 2023 forecast labour cost, excluding overtime.

2022 and 2023 Rate Base Allowances

May 2021

Table of Contents

1.0 Introduction

It is common practice for a utility's rate base to include allowances for: (i) funds used during construction ("AFUDC"); (ii) cash working capital ("CWC Allowance"); and (iii) materials and supplies ("Materials Allowance").[1]

For this Application, Newfoundland Power Inc. ("Newfoundland Power" or the "Company") has reviewed its CWC Allowance and Materials Allowance to reflect any changes that have occurred since the last detailed reviews.[2]

The CWC Allowance calculated for 2022 and 2023 is $6,548,000 and $6,800,000, respectively. This is approximately 1.1% of forecast 2022 regulated cash operating expenses and approximately 1.2% of forecast 2023 regulated cash operating expenses.[3]

The Materials Allowance calculated for 2022 and 2023 is $8,756,000 and $8,905,000, respectively. This reflects a revised expansion factor for the calculation of expansion inventory of 19.08%.[4]

2.0 CWC Allowance

2.1 Methodology

The inclusion of a CWC Allowance in rate base, and the use of a lead/lag study to calculate the allowance, are accepted practices for regulated utilities. A lead/lag study recognizes that the utility provides service to customers prior to the receipt of payment for that service. It also recognizes that there is generally a delay in payment by the utility for the goods and services it acquires.

A lead/lag study analyzes transactions over a period of time to determine: (i) for each revenue stream, the average number of lag days between the provision of service to customers and the receipt of payment for that service from customers (the "revenue lags"); and (ii) for each expense, the average number of lag days between the provision of service to customers and the date that the utility pays for the goods and services that it acquires to provide service (the "expense lags"). The difference between these 2 lags is referred to as a "net lag" or "net lead."

A net lag occurs when the payment of an expense precedes the collection of its related revenue stream. In this situation, the utility's investors must supply capital to finance the expense until receipt of the related revenue. A net lead position occurs in the opposite situation with the opposite impact.

---

[1] Newfoundland and Labrador Hydro's ("Hydro") rate base includes these 3 allowances in addition to a fuel inventory allowance.

[2] The last CWC Allowance and Materials Allowance review was completed for the Company's *2019/2020 General Rate Application* and formed part of the settlement agreement reached in relation to that application.

[3] This compares to $9,726,000 and $9,817,000, or 1.8% of forecast regulated cash operating expenses, used in 2019 and 2020. See *Section 2.2* of this report for further detail.

[4] This compares to a Materials Allowance of $5,668,000 and $5,775,000, which included an expansion factor of 24.05%, used in 2019 and 2020.

Once the revenue lags and expense lags are determined, the calculation of the CWC Allowance involves the following steps:

(i) Weight each revenue lag by its related revenue stream to calculate the total weighted average revenue lag.
(ii) Weight each expense lag by its related expense to calculate the total weighted average expense lag.
(iii) Subtract the weighted average expense lag from the weighted average revenue lag and divide the result by 365 days. This is the CWC factor.[5]
(iv) Multiply the CWC factor by the total regulated expenses to calculate the average amount of working capital required to finance the expenses.
(v) Add to the amount determined in step 4 to the net impact of the collection and payment of the harmonized sales tax ("HST") on working capital. The result is the CWC Allowance.

The CWC Allowance determined via a lead/lag study is indicative of a utility's average daily working capital requirements.

2.2 Leads and Lags: 2022 and 2023

General

In determining its 2022 and 2023 forecast cash working capital allowance, each of the individual revenue and expense lags were reviewed and updated to reflect any observed changes in revenue/expense streams. In addition, the timing and remittance of HST payments were also reviewed and updated.

Newfoundland Power's lead/lag study is based on 2020 actual data as it represents the most recent historical results available at the time.[6] There have been no material changes to the Company's billing and collection procedures or to its payment procedures since 2020. In addition, there are no material changes forecast for the 2022 and 2023 test years.

Through the lead/lag study, Newfoundland Power has determined: (i) its revenue lags; (ii) its expense lags; and (iii) the leads/lags associated with HST for 2022 and 2023 test years. Together, these leads and lags form the basis for the 2022/2023 CWC Allowance.

The leads and lags calculated have been applied to the Company's forecast 2022 and 2023 test year data to calculate the proposed CWC Allowance. These calculations are summarized on the following page.

---

[5] In a net lag situation, the CWC factor represents the percentage of expenses that has to be financed by the utility's investors during the year. Investor funding is necessitated by the fact that the cash outflows for expenses preceded the cash inflows for the related revenues. The CWC Allowance for a net lag is added to the rate base in order to provide a utility with a reasonable opportunity to recover the cost of the related investor-supplied funding. In a net lead situation, the opposite is true.

[6] Billing and collection procedures for 2020 were normalized to exclude the impacts of COVID-19 such as: (i) suspended disconnection practices during 2020; and (ii) a one-time bill credit issued in July 2020 in lieu of the annual July 1st Rate Stabilization Adjustment.

Revenue Lag

The revenue lag was calculated by analyzing all of the Company's revenue streams and accounts receivable for 2020 to determine the average number of lag days between when service is provided to customers and when payment for the service is received from customers.

Newfoundland Power has two distinct revenue streams which can broadly be described as "consumer billings" and "other billings."

Consumer billings included in the calculation of the CWC Allowance are composed of: (i) electricity billings and related municipal tax billings; (ii) forfeited discounts and interest earned on overdue accounts receivable; (iii) ancillary items such as connection/reconnection fees; and (iv) HST.

Other billings are comprised of pole rentals, work done by the Company for others, and various miscellaneous revenues and HST.

Revenue lags were calculated for consumer billings and other billings. These were weighted, based on the percentage of the total 2022 and 2023 forecast billings represented by each, to produce a total weighted average revenue lag of 35.45 days for 2022 and 35.49 days for 2023.[7] These are set out in Schedule 1 of Appendices A and B.

Expense Lag

The expense lag was calculated by analyzing each of the Company's cash operating expenses for 2020 to determine the average number of lag days between when service is provided to customers and when payment is made for the goods and services that are acquired to provide service.

The calculated expense lag of each cash operating expense was weighted based on the percentage of the total 2022 and 2023 forecast cash operating expenses represented by each to produce a total weighted average expense lag for the Company of 31.30 days for 2022 and 31.11 days for 2023.[8] These are set out in Schedule 2 of Appendices A and B.

For 2022 and 2023, the expense lag associated with the payment of corporate income taxes and purchased power has increased compared the 2019/2020 lead/lag study. In determining the expense lag for corporate income taxes, the actual 2020 tax payments were analyzed and weighted against the average service lag. For the 2020 tax year, there was a $2 million final tax payment made in March 2021 related to the 2020 fiscal year.[9] This payment increased the 2020 income tax expense lag. In determining the expense lag for purchased power, the actual 2020

[7] By comparison, the revenue lag included in the 2019 and 2020 test year cash working capital study was 35.84 days for 2019 and 35.83 days for 2020.

[8] By comparison, the expense lag included in the 2019 and 2020 test year cash working capital study was 29.44 days for 2019 and 29.31 days for 2020.

[9] The 2020 tax return is not finalized. As of December 31, 2020, the Company expected an income tax payable associated with the 2020 tax year of $1.8 million. On March 1, 2021, the Company made a final tax instalment associated with the 2020 tax year of $2.0 million.

payments were analyzed and weighted against the average service lag. Purchased power represented a greater portion of total cash operating expenses in 2020 compared to the 2017 fiscal year, therefore a higher weighting was put towards the lag calculated for this expense, increasing the overall expense lag in 2020.[10]

HST Adjustment

HST is collected from customers on certain billed revenues and paid to suppliers on certain expenses and capitalized costs. The difference between HST collections and HST payments in each month is settled with government on the last day of the month that follows the month in which the HST was billed or, if that day is not a business day, on the first business day thereafter.

On average, HST on most of Newfoundland Power's billings is collected from customers before it is settled with government. The Company has use of these funds between the collection date and the settlement date. This serves to reduce the necessary CWC Allowance.

On average, HST billed by Newfoundland Power's suppliers is paid to those suppliers before it is settled with government. The Company has to finance the HST between the payment date and the settlement date. This serves to increase the necessary CWC Allowance.

The net HST impact is an increase in the Company's proposed 2022 and 2023 test year CWC Allowance of $44,000 in 2022 and $15,000 in 2023.[11] Newfoundland Power's 2022 and 2023 HST adjustments are set out in Schedule 3 of Appendices A and B.

2.3 Test Year CWC Allowance: 2022 and 2023

Newfoundland Power's proposed 2022 and 2023 test year CWC Allowance based on the calculated revenue lag, expense lag and HST adjustment is $6,548,000 in 2022 and $6,800,000 in 2023. These are set out in Schedule 4 of Appendices A and B.[12]

The effect of the proposed 2022 and 2023 CWC Allowance is to provide Newfoundland Power with a reasonable opportunity to recover its cost of providing regulated service.

3.0 Materials and Supplies Allowance

The inclusion of a Materials Allowance in rate base is an accepted practice for regulated utilities. The Materials Allowance provides regulated utilities with a means to reasonably recover the cost of financing inventories. In determining the amounts of materials and supplies to include in rate

---

[10] Effective July 1, 2018, the Company's purchased power costs increased by 4.1% as a result of the Newfoundland and Labrador Board of Commissioners of Public Utilities' (the "Board") approval of Hydro's interim rate increase in May 2018. Effective October 1, 2019, there was an additional increase in the Company's purchased power costs of approximately 6.4% as a result of the Board's approval of Hydro's final rate increase in September 2019.

[11] By comparison, the 2019 test year HST adjustment of $296,000 and 2020 HST adjustment of $242,000 also increased the 2019 and 2020 CWC Allowance.

[12] By comparison, the CWC Allowance included in the 2019 test year was $9,726,000 and $9,817,000 in the 2020 test year.

base, Newfoundland Power is required to exclude that portion that it identifies as expansion inventory.[13]

The Board approved the calculation of Newfoundland Power's rate base including a Materials Allowance based upon: (i) a 13-month average versus a simple average; and (ii) expansion inventory of 24.05% in the *2019/2020 General Rate Application* settlement agreement.

For the *2022/2023 General Rate Application*, Newfoundland Power has revised its expansion factor used in the calculation of the Materials Allowance based on a review of actual inventories in 2020 used for expansion projects. The revised expansion factor for the 2022 and 2023 test year is 19.08%, versus 24.05% calculated for the 2020 test year.

[13] In Order No. P.U. 1 (1974), Newfoundland Power was directed by the Board to identify and exclude from rate base all inventories and supplies related to expansion of the electrical system. Essentially, the Board noted that materials and supplies related to future expansion were similar in nature to work in progress in that they are held to provide future service. Similar to the treatment of work in progress, materials and supplies related to expansion are excluded in the calculation of rate base.

Newfoundland Power Inc.

2022 Forecast Revenue Lag

	Cash Inflows	2022 Forecast[1] ($000s)	Percent of Total	Net Lag Days	Weighted Average Lag Days
1	Consumer Billings	738,831	99.02%	34.98	34.64
2	Other Billings	7,279	0.98%	83.04	0.81
3	Total	746,110	100.00%		**35.45**

[1] Reconciliation to 2022 Revenue Requirement ($000s):

Total Billings Above	746,110
Rate Stabilization Adjustments	(2,460)
Municipal Tax Billings	(17,203)
Billings Recorded as Revenue	726,447
Revenue Excluded from CWC Allowance	
Revenue Accrual (non-cash)	(2,119)
Equity Portion of AFUDC	874
Total Revenue	725,202
Deduct: Other Revenue	(9,838)
2022 Revenue Requirement from Rates	715,364

Newfoundland Power Inc.

2022 Forecast Expense Lag

		2022 Forecast	Adjustments[1] ($000s)	Cash Operating Expenses	Percent of Total	(Lead) Lag Days	Weighted Average (Lead) Lag Days
	Operating Expenses						
1	Labour	39,787		39,787	6.96%	36.61	2.55
2	Vehicle Expenses	1,702		1,702	0.30%	45.21	0.13
3	Operating Materials	1,266		1,266	0.22%	45.21	0.10
4	Inter-Company Charges	2,261		2,261	0.40%	45.21	0.18
5	Plants, Subs, System Ops & Buildings	3,434		3,434	0.60%	45.21	0.27
6	Travel	937		937	0.16%	45.21	0.07
7	Tools and Clothing Allowance	1,244		1,244	0.22%	45.21	0.10
8	Conservation	4,004		4,004	0.70%	45.21	0.32
9	Miscellaneous	2,239		2,239	0.39%	45.21	0.18
10	Bank Service Charges & PUB Assessment	1,162		1,162	0.20%	(43.66)	(0.09)
11	Uncollectible Bills	2,172	2,172	-	0.00%		-
12	Insurance	2,306		2,306	0.40%	(167.50)	(0.68)
13	Pension Expense	915	(1,815)	2,730	0.48%	22.14	0.11
14	Other Post Employment Benefits	7,831	4,184	3,647	0.64%	29.45	0.19
15	Severance and Other Employee Costs	131		131	0.02%	45.21	0.01
16	Education and Training	391		391	0.07%	45.21	0.03
17	Trustee & Directors' Fees	701		701	0.12%	17.02	0.02
18	Other Company Fees	5,154		5,154	0.90%	45.21	0.41
19	Stationery & Copying	256		256	0.04%	45.21	0.02
20	Equipment Rental & Maintenance	832		832	0.15%	45.21	0.07
21	Telecommunications	1,562		1,562	0.27%	45.21	0.12
22	Postage	1,244		1,244	0.22%	45.21	0.10
23	Advertising	2,005		2,005	0.35%	45.21	0.16
24	Vegetation Management	2,401		2,401	0.42%	45.21	0.19
25	Computer Equipment & Software	2,856		2,856	0.50%	45.21	0.23
26	Gross Operating Expenses	88,793		84,253			
27	Less: GEC	(5,350)		(5,350)	-0.94%	28.67	(0.27)
28	Net Operating Expenses	83,443		78,903			
29	Less: Non-Regulated Expenses	(3,356)		(3,356)	-0.59%	39.54	(0.23)
30	**Regulated Operating Expenses**	80,087		75,547			
31							
32	**Purchased Power**	464,811		464,811	81.25%	35.57	28.90
33							
34	**Current Income Tax**						
35	Total Tax	21,147	7,660	13,487			
36	Plus: Tax Effects of Non-Regulated Expenses	1,007		1,007			
37	Regulated Current Income Tax	22,154		14,494	2.53%	46.70	1.18
38							
39	**Municipal Tax Paid**			17,203	3.01%	(102.06)	(3.07)
40							
41	**Cash Operating Expenses in CWC Allowance**			572,055	100.00%		**31.30**
42							
43	**Costs Excluded from CWC Allowance**						
44	Return on Rate Base	89,173					
45	Depreciation Expense	70,956					
46	Deferred cost recoveries and amortizations[2]	(4,739)					
47		155,390					
48							
49	**2022 Revenue Requirement**	722,442					

[1] Represents items that are not reoccurring cash operating expenses.

[2] Includes deferred cost recoveries and amortizations (-$892,000), the amortization of hearing costs ($294,000), the deferred recovery of conservation costs (-$7,170,000), the deferred recovery of electrification costs (-$3,014,000), the amortization of electrification costs ($134,000) and the amortization of conservation costs ($5,909,000). See Section 3.5 of the Company's evidence.

Newfoundland Power Inc.

2022 Forecast HST Adjustment

		HST ($000s)	Net (Lead) Lag Days	CWC Allowance[1] ($000's)
1	Consumer Billings	(110,333)	(25.86)	(7,812)
2	Other Billings	(1,151)	37.41	118
3	Purchased Power	69,722	40.48	7,732
4	Operating Expenses	4,655	0.42	6
5				**44**

[1] (Lead) Lag Days / 365 * HST.

Newfoundland Power Inc.

2022 Forecast Cash Working Capital Allowance

	CWC Factor	
1	Revenue Lag Days (Schedule 1)	35.45
2	Expense Lag Days (Schedule 2)	(31.30)
3	Net Lag Days	4.15
4		
5	CWC Factor (4.15 days divided by 365 days)	1.137%
6		
7		
8		
9		
10	**CWC Allowance**	
11		
12	Total Cash Operating Expenses (Schedule 2)	572,055
13	CWC Factor	1.137%
14		6,504
15	HST Adjustment (Schedule 3)	44
16	**CWC Allowance**	**6,548**

Newfoundland Power Inc.

2023 Forecast Revenue Lag

	Cash Inflows	2023 Forecast[1] ($000s)	Percent of Total	Net Lag Days	Weighted Average Lag Days
1	Consumer Billings	735,152	98.94%	34.98	34.61
2	Other Billings	7,861	1.06%	83.04	0.88
3	Total	743,013	100.00%		**35.49**

[1] Reconciliation to 2023 Revenue Requirement ($000s):

Total Billings Above	743,013
Rate Stabilization Adjustments	(2,438)
Municipal Tax Billings	(17,109)
Billings Recorded as Revenue	723,466
Revenue Excluded from CWC Allowance	
Revenue Accrual (non-cash)	(1,131)
Equity Portion of AFUDC	1,333
Total Revenue	723,668
Deduct: Other Revenue	(10,865)
2023 Revenue Requirement from Rates	712,803

Newfoundland Power Inc.

2023 Forecast Expense Lag

		2023 Forecast	Adjustments[1] ($000s)	Cash Operating Expenses	Percent of Total	(Lead) Lag Days	Weighted Average (Lead) Lag Days
	Operating Expenses						
1	Labour	41,566		41,566	7.34%	36.61	2.69
2	Vehicle Expenses	1,730		1,730	0.31%	45.21	0.14
3	Operating Materials	1,287		1,287	0.23%	45.21	0.10
4	Inter-Company Charges	2,328		2,328	0.41%	45.21	0.19
5	Plants, Subs, System Ops & Buildings	3,492		3,492	0.62%	45.21	0.28
6	Travel	937		937	0.17%	45.21	0.07
7	Tools and Clothing Allowance	1,265		1,265	0.22%	45.21	0.10
8	Conservation	4,841		4,841	0.86%	45.21	0.39
9	Miscellaneous	2,223		2,223	0.39%	45.21	0.18
10	Bank Service Charges & PUB Assessment	1,181		1,181	0.21%	(43.66)	(0.09)
11	Uncollectible Bills	2,208	2,208	-	0.00%	0.00	-
12	Insurance	2,345		2,345	0.41%	(167.50)	(0.69)
13	Pension Expense	-5,172	(7,781)	2,609	0.46%	22.14	0.10
14	Other Post Employment Benefits	7,943	4,021	3,922	0.69%	29.45	0.20
15	Severance and Other Employee Costs	133		133	0.02%	45.21	0.01
16	Education and Training	397		397	0.07%	45.21	0.03
17	Trustee & Directors' Fees	712		712	0.13%	17.02	0.02
18	Other Company Fees	5,386		5,386	0.95%	45.21	0.43
19	Stationery & Copying	260		260	0.05%	45.21	0.02
20	Equipment Rental & Maintenance	897		897	0.16%	45.21	0.07
21	Telecommunications	1,588		1,588	0.28%	45.21	0.13
22	Postage	1,202		1,202	0.21%	45.21	0.10
23	Advertising	1,930		1,930	0.34%	45.21	0.15
24	Vegetation Management	2,441		2,441	0.43%	45.21	0.19
25	Computer Equipment & Software	3,446		3,446	0.61%	45.21	0.28
26	Gross Operating Expenses	86,566		88,118			
27	Less: GEC	(2,812)		(2,812)	-0.50%	28.67	(0.14)
28	Net Operating Expenses	83,754		85,306			
29	Less: Non-Regulated Expenses	(3,561)		(3,561)	-0.63%	39.54	(0.25)
30	**Regulated Operating Expenses**	80,193		81,745			
31							
32	**Purchased Power**	459,924		459,924	81.27%	35.57	28.91
33							
34	**Current Income Tax**						
35	Total Tax	23,130	17,051	6,079			
36	Plus: Tax Effects of Non-Regulated Expenses	1,068		1,068			
37	Regulated Current Income Tax	24,198		7,147	1.26%	46.70	0.59
38							
39	**Municipal Tax Paid**			17,109	3.02%	(102.06)	(3.09)
40							
41	**Cash Operating Expenses in CWC Allowance**			565,925	100.00%		**31.11**
42							
43	**Costs Excluded from CWC Allowance**						
44	Return on Rate Base	89,844					
45	Depreciation Expense	75,252					
46	Deferred cost recoveries and amortizations[2]	(3,752)					
47		161,344					
48							
49	**2023 Revenue Requirement**	725,659					

[1] Represents items that are not reoccurring cash operating expenses.

[2] Includes deferred cost recoveries and amortizations ($444,000), the amortization of hearing costs ($353,000), the deferred recovery of conservation costs (-$7,006,000), the deferred recovery of electrification costs (-$3,944,000), the amortization of conservation costs ($5,966,000) and the amortization of electrification costs ($435,000). See Section 3.5 of the Company's evidence.

Newfoundland Power Inc.

2023 Forecast HST Adjustment

		HST ($000's)	Net (Lead) Lag Days	CWC Allowance[1] ($000's)
1	Consumer Billings	(109,637)	(25.86)	(7,769)
2	Other Billings	(1,238)	37.41	127
3	Purchased Power	68,989	40.48	7,651
4	Operating Expenses	4,921	0.42	6
5				**15**

[1] (Lead) Lag Days / 365 * HST.

Newfoundland Power Inc.

2023 Forecast Cash Working Capital Allowance

	CWC Factor	
1	Revenue Lag Days (Schedule 1)	35.49
2	Expense Lag Days (Schedule 2)	(31.11)
3	Net Lag Days	4.38
4		
5	CWC Factor (4.38 days divided by 365 days)	1.199%
6		
7		
8		
9		
10	**CWC Allowance**	
11		
12	Total Cash Operating Expenses (Schedule 2)	565,925
13	CWC Factor	1.199%
14		6,785
15	HST Adjustment (Schedule 3)	15
16	**CWC Allowance**	**6,800**

Customer, Energy and Demand Forecast

May 2021

Table of Contents

1.0 Introduction

The Customer, Energy and Demand Forecast is prepared annually and forms the foundation of Newfoundland Power Inc.'s ("Newfoundland Power" or the "Company") planning process. The forecast is a key input in developing estimates of capital expenditures required to ensure the electrical system meets the demands associated with both customer growth and energy sales. The forecast also directly addresses the estimation of future revenue from electricity sales and the Company's single largest expenditure, purchased power.

The forecast was created as of May 2021.

2.0 Forecast Methodology

Newfoundland Power provides electrical service to 3 distinct categories of customers. These are Domestic, General Service and Street and Area Lighting customers. In 2020, Domestic customers accounted for 61.9% of total energy sales, while General Service and Street and Area Lighting customers accounted for 37.5% and 0.6%, respectively.

2.1 Domestic

The Domestic category includes Rate #1.1 Domestic Service and Rate #1.1S Domestic Seasonal – Optional. The Domestic category primarily refers to residential dwellings, such as single detached homes, single attached homes, apartments and mobile homes. This category also includes non-residential services, such as cottages, personal use garages and other metered services that qualify for the Domestic rate category. Residential customers use electricity primarily for space and water heating, and the operation of miscellaneous appliances and lighting.

In this category, a customer/average use methodology is employed where growth in the number of customers is primarily based on forecast housing completions. Average use is forecast using an end-use/econometric model that includes the market share for electric space heating, household disposable income and the marginal price of electricity in the current and previous year. The model also includes variables to reflect the impacts on energy sales of electrification and conservation and demand management ("CDM") programs, as well as the market penetration of heat pumps.

2.2 General Service

The General Service category primarily refers to commercial, institutional and industrial customers. While the Domestic category represents a relatively homogenous group of customers, the General Service category represents a diverse group whose activities include trade, finance, real estate, public administration, health, education, commercial services, transportation, manufacturing, mining, fishing, forestry and construction. These customers provide goods and services to the local market as well as for export. In 2020, approximately 84% of energy sales in this category were to customers in the service producing sector of the economy, while only 16% were in the goods producing sector.

From a forecasting perspective, the General Service category is divided into small General

Service, which includes Rate #2.1 General Service 0 – 100 kW (110 kVA), and large General Service, which includes Rate #2.3 General Service 110 kVA (100 kW) – 1000 kVA and Rate #2.4 General Service 1000 kVA and Over.

In the small General Service category, the growth in the number of customers is primarily based on forecast Domestic customer growth. Energy sales are forecast using an econometric model that includes the Gross Domestic Product ("GDP") for the service sector, the average price of electricity in the current year and the number of customers. The model also includes a variable to reflect the impact of electrification and CDM programs on energy sales.

Given the relatively small number of customers in the large General Service category, an informed opinion methodology is employed and energy sales are forecast on an individual customer basis.

2.3 Street and Area Lighting

Street and Area Lighting energy sales primarily relate to the number of fixtures required to meet the lighting needs of both municipalities and unincorporated communities. At the end of 2020, approximately 65,000 fixtures were installed.

Given the nature of this category, an end use forecasting methodology is employed. The Street and Area Lighting sales forecast is determined by multiplying the forecast quantity of high-pressure sodium ("HPS") and light-emitting diode ("LED") fixtures by the amount of electricity consumed for each fixture type and wattage.

2.4 Produced and Purchased

Total energy sales are calculated by adding Domestic, General Service, and Street and Area Lighting sales. Company use, system losses and wheeled energy are then added to total energy sales to obtain total produced, purchased and wheeled. Company use includes all electricity consumed in facilities owned by Newfoundland Power and used in the delivery of service to customers. System losses refer to energy that is lost during the transmission and distribution of energy between the source of supply and delivery to customers. Wheeled information is provided by Newfoundland and Labrador Hydro ("Hydro").[1]

Purchased energy is calculated by subtracting normal hydro production ("normal production") from the forecast of total produced and purchased. Each year, normal production is adjusted to reflect plant availability and any modifications to plants that may impact production.

2.5 Peak Demand

Newfoundland Power forecasts its native peak demand ("peak demand") to estimate its expected purchased power costs from Hydro throughout the forecast period.[2] A system load factor

[1] Wheeled energy represents energy that is supplied to Hydro's customers through Newfoundland Power's electrical system.

[2] Hydro's Billing Demand is determined by subtracting the load curtailment and generation credits from native peak.

methodology has been used by the Company to forecast peak demand since 2005 when demand charges were first introduced as a component to Newfoundland Power's Utility Rate from Hydro.[3]

Historically, peak demand has been forecast using a 15-year average system load factor. Use of a 15-year average system load factor captures the historical relationship between the Company's actual system peaks and actual system energy usage over the longer term.

For the *2022/2023 General Rate Application*, Newfoundland Power is forecasting peak demand using a 5-year average system load factor.[4] Use of a 5-year average system load factor recognizes changes in system conditions that have occurred in recent years. This includes declining energy requirements[5] and an increased penetration of heat pumps throughout the Company's service territory.[6]

The accuracy of the 5-year average system load factor in forecasting peak demand is reasonably comparable to the accuracy of the 15-year average system load factor.[7] The approach is also consistent with sound public utility practice.[8]

Use of a 5-year average system load factor, as opposed to a 15-year average system load factor, increases Newfoundland Power's peak demand forecast by approximately 9 MW, or 0.7%, over the forecast period.

3.0 Key Forecast Assumptions

The forecasting process relies on a wide range of information related to the economy, energy prices, electrification and CDM activities, and other resource-based developments within Newfoundland Power's service territory.

---

3 Load factor is the ratio of the average demand on the electrical system to the peak demand on the system. Newfoundland Power's typical load factor is approximately 50%. Conceptually, this implies that the peak demand Newfoundland Power will expect in a year will be approximately twice the average demand for the year. Hydro's demand and energy wholesale rate was first approved by the Board in Order No. P.U. 44 (2004).

4 The 5-year average system load factor used by Newfoundland Power includes actual system load factors from 2015 to 2019. The Company's load factor in 2020 was the highest recorded system load factor in at least 30 years and was influenced by public health measures in effect to manage the COVID-19 pandemic. It was therefore excluded.

5 From 2015 to 2019, Newfoundland Power's produced and purchased energy requirements decreased by approximately 2% from 6,309 GWh to 6,173 GWh.

6 The penetration of heat pumps among Newfoundland Power's customers increased from approximately 4% in 2014 to approximately 18% in 2020. The Company is completing a load research study on heat pumps installed within its service territory to understand potential impacts on peak demand.

7 The variance of forecast peak demand using the 15-year average system load factor from actual peak demand ranged from -3.3% to 3.5% over the 2011 to 2019 period. The variance of forecast peak demand using the 5-year average system load factor from actual peak demand ranges from -3.1% to 2.6% over the same period.

8 In 2021, Newfoundland Power surveyed 12 Canadian utilities to understand their peak demand forecasting methodologies. Of the 12 surveyed utilities, 6 use methodologies similar to Newfoundland Power's load factor methodology, which relies on forecast energy consumption and historic energy and demand data. Of those, 1 utility uses 1 year of historical data, 3 utilities use 3 to 5 years of historical data, and 2 utilities use 10 years of historical data.

3.1 Economic Outlook

The economic assumptions used in preparing the forecast are based on The Conference Board of Canada's *Provincial Medium-Term Forecast,* dated March 2021. A table summarizing the key economic indicators used in preparing the forecast is provided in Appendix A.

The provincial economy was affected by the COVID-19 pandemic in 2020. Real GDP contracted by 3.5% in 2020. Weakness in investment and household spending were the main factors behind the decline in economic activity.[9]

Provincial employment was negatively affected in 2020. According to The Conference Board of Canada:

> *"Employment fell by an estimated 5.9 percent in 2020…, the fifth drop in the past seven years. Not surprising, there were major losses in the construction, transportation and warehousing, accommodation and food services, and arts and entertainment sectors, all of which were heavily impacted by closures resulting from the COVID-19 pandemic."*[10]

Investment in major construction projects in the province was also negatively affected in 2020. The Conference Board of Canada observed that:

> *"Unfortunately, at the same time that COVID-19 hit the province, oil prices began falling fast, even dropping into negative territory briefly last April. As a result, the oil and gas industry was forced to make some significant investment changes. Construction was almost immediately halted at the West White Rose project and plans for the Bay du Nord project were put on hold…. At the end of last summer, Husky Energy announced that it would delay the West White Rose project until at least 2022."*[11]

The winding down of construction on the Muskrat Falls Project was another major factor affecting non-residential investment in the province in 2020. On the residential side, construction activity declined by more than 30%.[12]

Economic activity in the province is expected to begin to recover in 2021.

The province's unemployment rate is expected to return to pre-pandemic levels in the final quarter of 2021.[13] Consumer spending in the services sector is expected to improve, with gains of 4.0% in 2021 and 6.0% in 2022.[14]

Growth in the province's non-residential investment sector remains uncertain for 2021. A rebound in world oil prices to above $60 per barrel in February 2021 may lead to further

---

9 The Conference Board of Canada, *A Softer Fall in 2020, a Modest Gain in 2021: Newfoundland and Labrador's* Two-Year Outlook ("*Newfoundland and Labrador's Two-Year Outlook*"), March 18, 2021, page 3.
10 Ibid., page 7.
11 Ibid., page 8.
12 Ibid., page 9.
13 Ibid., page 7.
14 Ibid., page 8.

investment in the oil and gas sector.[15] However, growth in non-residential investment will increase by only 0.6% in 2021.[16]

Residential investment is expected to remain weak. Housing starts dropped by close to 20% in 2020, after years in negative territory. This pattern is expected to continue.[17]

While the effects of the COVID-19 pandemic are expected to ease in 2021, the provincial economic outlook beyond 2021 remains weak. The provincial unemployment rate is expected to remain the highest in Canada.[18] GDP, while forecast to increase by 4.3% in 2022, is expected to decline by 1.2% in 2023.[19] Housing starts are forecast to decline annually.[20] Provincial Government spending is expected to remain constrained as the province addresses its debt obligations and annual fiscal deficits.[21]

3.2 Energy Prices Outlook

Changes in energy prices have a direct impact on energy sales through the inclusion of price elasticity effects in the various models. Overall, customer response to changes in the price of electricity in the short-term is relatively inelastic. Current analysis indicates that a 1% increase in the price of electricity will result in a 0.23% decrease in energy sales. The analysis indicates the response will vary depending on the timeframe and rate category. In addition, changes in oil prices can impact the market share of electricity in the competitive space heating market.

Electricity price forecasts are developed based on information available internally and information provided by Hydro. The energy sales forecast under existing rates includes: (i) a 3% increase on July 1, 2021 related to the annual review of the Rate Stabilization Account;[22] and (ii) annual increases of 2.25% effective January 1st of each year from 2022 to 2026.[23] Newfoundland Power's proposed 0.8% increase in customer rates effective March 1, 2022 is also included in the forecast under proposed rates.

Furnace oil prices are forecast to increase by approximately 26% in 2021 and decline by approximately 2% in 2022. Annual increases of 4% are forecast to occur over the 2023 to 2026 period.[24] Near-term changes in furnace oil prices reflect volatility in world oil prices following the onset of the COVID-19 pandemic.

---

15 Ibid., page 8.
16 Ibid., page 9.
17 Ibid., page 9.
18 Ibid., page 7.
19 See Attachment 1, page 2.
20 See Attachment 1, page 2.
21 The Conference Board of Canada, *Newfoundland and Labrador's Two-Year Outlook*, March 18, 2021, page 10.
22 See Response to Request for Information PUB-NLH-001 filed in relation to Hydro's *Application for Recovery of Deferred 2020 Supply Costs*.
23 Annual rate increases of 2.25% are based on the Provincial Government's April 2019 release *Protecting You from the Cost Impacts of Muskrat Falls.*
24 Based on the US Energy Information Administration's *Short-Term Energy Outlook*, September 2020.

3.3 Electrification and CDM Impacts

The energy sales component of the forecast includes the impact of electrification and CDM programs. The adjustments to the forecast are consistent with the *Electrification, Conservation and Demand Management Plan: 2021-2025*.[25]

3.4 Net Metering Service Option

The Net Metering Service Option was introduced in 2017 and permits customers to install generation on their premises to offset part or all of their electrical requirements. As of December 31, 2020, Newfoundland Power's customers have installed 11 net metering projects. This includes: (i) 9 solar projects ranging in capacity from 3.0 kW and 14.4 kW; and (ii) 2 wind projects with capacities of 5 kW and 12.8 kW. The total installed capacity of the Company's Net Metering Service option is 95.5 kW.[26]

Given the low installed capacity of Newfoundland Power's Net Metering Service Option to date, no adjustments have been made to the forecast.

3.5 Other Inputs

Information from a number of other sources is used in preparing the forecast. Newfoundland Power surveyed approximately 105 large General Service customers representing approximately 175 customer accounts in 2021 to request information on future load requirements. This information, along with information gathered from the Company's regional operations, the Atlantic Provinces Economic Council, and the provincial and federal governments, is also incorporated into the large General Service forecast.

4.0 Customer and Energy Forecast

Newfoundland Power's energy sales have declined each year since 2016.[27] This is in contrast to the annual growth in energy sales traditionally experienced by the Company.[28]

In 2020, Newfoundland Power's energy sales were affected by public health measures introduced by the Provincial Government to manage the COVID-19 pandemic. These public health measures have continued into 2021, but are expected to subside throughout the year as the Provincial Government implements its vaccination plans. The Company is forecasting that electricity sales in 2022 and 2023 will no longer be reflective of public health measures introduced to manage the COVID-19 pandemic.

---

[25] See *Volume 2, Supporting Materials, Tab 7, Electrification, Conservation and Demand Management Plan: 2021-2025* .

[26] See Newfoundland Power's *2020 Net Metering Service Option Annual Report* filed with the Board on March 26, 2021.

[27] Newfoundland Power's annual energy sales declined by an average of approximately 0.8% over the 2016 to 2020 period.

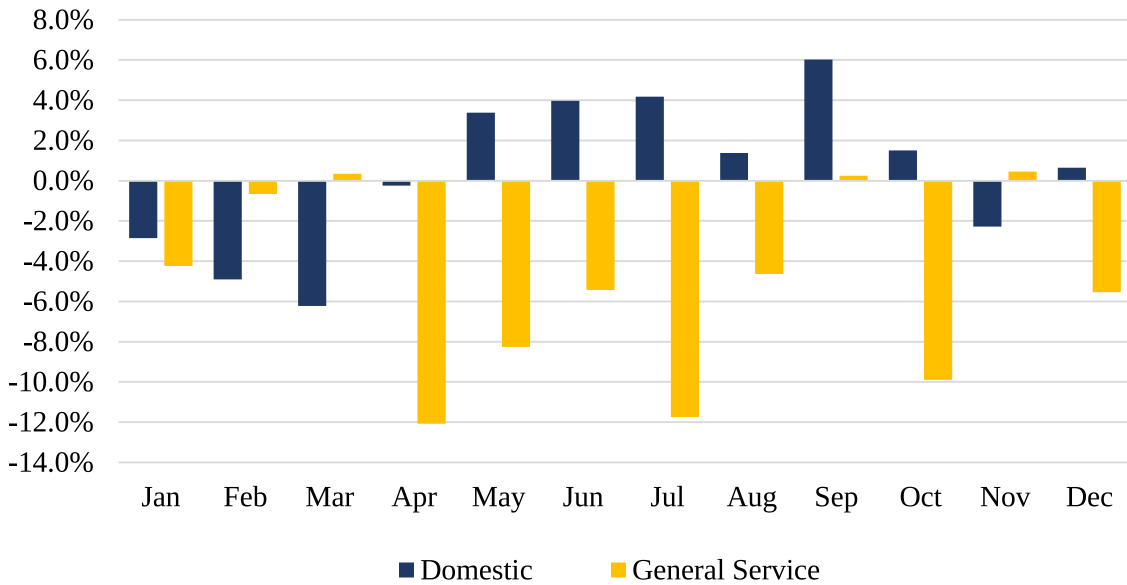
[28] Between 2004 and 2015, Newfoundland Power experienced annual sales growth of approximately 1.6%.

4.1 2020 Energy Sales

Newfoundland Power's energy sales declined by 2.0% in 2020.[29] This represents the largest year-over-year decline in the Company's energy sales. Newfoundland Power's energy sales in 2020, specifically in the General Service and Domestic categories, were affected by the public health measures introduced by the Provincial Government to manage the COVID-19 pandemic.[30]

Figure 2 shows the change in monthly sales for the General Service and Domestic rate classes in 2020 compared to 2019.

Figure 2:
Change in General Service and Domestic Energy Sales
2020 versus 2019[31]



In the first 3 months of 2020, prior to the introduction of public health measures, Domestic energy sales declined by an average of 4.7%.[32] This is consistent with the trend of weak Domestic energy sales observed in recent years. For the remaining 9 months of 2020, Domestic energy sales increased by an average of 2.1% compared to 2019.[33] This reflects public health measures, which resulted in Domestic customers spending more time at home.

---

29 Without the additional day of electricity sales provided by a leap year in February 2020, Newfoundland Power's energy sales would have declined by 2.3% compared to 2019 (1 day / 365 days = 0.274%).

30 The Provincial Government initiated public health measures to address the spread of COVID-19 in March 2020. On March 18, 2020, a Public Health Emergency was declared, resulting in the closure of non-essential businesses and organizations. Public health measures have continued in varying degrees throughout 2020 and into 2021.

31 February 2020 Domestic and General Service energy sales were adjusted to account for 2020 having an additional day of electricity sales due to the 2020 leap year.

32 The average monthly change in Domestic energy sales in the first 3 months of 2020 versus 2019 was -4.7% ((-2.9% + -4.9% + -6.2%) / 3 = -4.7%).

33 The average monthly change in Domestic energy sales in the last 9 months of 2020 versus 2019 was 2.1%. ((-0.2% + 3.4% + 4.0% + 4.2% + 1.4% + 6.0% + 1.5% + -2.3% + 0.6%) / 9 = 2.1%).

In the first 3 months of 2020, prior to the introduction of public health measures, General Service energy sales declined by an average of 1.5% compared to 2019.[34] For the remaining 9 months of 2020, General Service energy sales declined by an average of 6.3%.[35] This reflects public health measures, which caused many General Service customers to limit operations or close entirely.

Overall, Newfoundland Power's decline in General Service energy sales in the last 9 months of 2020 were somewhat offset by increased energy sales to Domestic customers over the same period.[36]

4.2 Customer and Energy Sales Forecast (2021–2023)

Newfoundland Power is forecasting that energy sales in 2021 will begin to resemble energy sales in years prior to 2020. This is largely due to the Provincial Government vaccination plan, which is expected to result in the large-scale inoculation of residents throughout 2021.[37]

Over the 2022 to 2023 forecast period, energy sales are expected to be influenced primarily by key economic indicators, such as service sector GDP, household disposable income, housing starts and completions, and energy prices.

Appendix B provides actual customer and energy sales for 2019 and 2020, and forecast customer and energy sales for 2021 to 2023 under both existing and proposed rates.

With a weak economic outlook, customer growth is expected to remain low over the forecast period. The total number of customers is forecast to increase by 0.4% in 2021 and 2022 and 0.3% in 2023.

Challenging economic conditions and customer interest in heat pumps are expected to contribute to a decline in energy sales over the forecast period. Forecast energy sales also includes the impact of customer electrification and CDM programs. Energy sales under existing rates are forecast to decrease by 0.2%, 0.3% and 0.6% in 2021, 2022 and 2023 respectively.[38] Energy sales under proposed rates, which include the elasticity effects of the proposed 0.8% customer rate increase, are forecast to decrease by 0.4% in 2022 and 0.7% in 2023.

---

[34] The average monthly change in General Service energy sales in the first 3 months of 2020 versus 2019 was -1.5% ((-4.2% + -0.7% + 0.3%) / 3 = -1.5%).

[35] The average monthly change in General Service energy sales in the last 9 months of 2020 versus 2019 was 6.3% ((-12.1% + - 8.3% + -5.4% + -11.7% + -4.6% + 0.2% + -9.9% + 0.5% + -5.5%) / 9 = -6.3%).

[36] Due to the effect that public health measures had on Newfoundland Power's Domestic and General Service energy sales in 2020, adjustments to 2020 average use were required to normalize these effects in the Company's average use models.

[37] On April 8, 2021, the Provincial Government released an update to its *COVID-19 Immunization Timeline*. It indicated that the first dose of COVID-19 vaccines will be available to all eligible residents by July 2021. As of May 16, 2021, approximately 46% of eligible residents in Newfoundland and Labrador had received their first vaccination dose.

[38] Energy sales in 2020 were positively impacted by approximately 0.3% due to 2020 being a leap year.

Domestic

Growth in the number of Domestic customers is largely a result of housing starts and completions. Based on The Conference Board of Canada forecasts of housing starts and completions, the number of Domestic customers is forecast to grow by 0.4% in 2021, 2022 and 2023.

Domestic electricity consumption is a function of the major end uses in the home, such as space heating, water heating, lighting, and major appliances. Changes in energy prices, household disposable income, electrification and CDM programs, and the penetration of heat pumps also have an impact on electricity consumption. Under proposed rates, the average use of energy is forecast to decrease by 2.0% in 2021, 1.9% in 2022 and 1.2% in 2023.

The combined impact of the increased number of customers and changes in average use will result in a decrease in Domestic energy sales under proposed rates of 1.5% in 2022 and 0.9% in 2023.

General Service

In the small General Service Rate #2.1, customers and energy sales growth are dependent on growth in the service producing sector of the GDP, changes in the price of electricity and the impact of electrification and CDM programs. In the large General Service Rate #2.3 and Rate #2.4, energy sales are primarily determined by changes in the load of larger customers in the goods producing sector. Information obtained from specific customers is incorporated into forecasts for Rate #2.3 and Rate #2.4.

Overall, the number of General Service customers is forecast to grow by 0.2% in 2021, 2022 and 2023. Under proposed rates, General Service energy sales are forecast to increase by 1.6% in 2022 and decrease by 0.2% in 2023. The energy sales increase in 2022 is primarily related to the recovery of General Service energy sales as economic activity recovers from the COVID-19 pandemic. The decline in energy sales in 2023 is primarily related to reduced construction activities in the oil and gas sector.

Street and Area Lighting

The number of Street and Area Lighting customers is forecast to increase by 0.2% in 2021 and 0.1% in 2022 and 2023. Energy sales are forecast to decrease by 5.0% in 2021, 9.1% in 2022 and 9.7%% in 2023. The decrease in energy sales is due to the Company's 6-year *LED Street Lighting Replacement Plan,* which will replace all HPS street light fixtures with more energy-efficient LED street light fixtures from 2021 to 2026.[39]

Produced and Purchased

Produced and purchased is the sum of total energy sales, company use and system losses. The forecast of company use is based on historical energy usage and information gathered from each of Newfoundland Power's operating areas with respect to the operation of these facilities.

[39] See Newfoundland Power's *2021 Capital Budget Application*. The first year of the plan was approved by the Board in Order No. P.U. 37 (2020).

System losses are based on historical information and are forecast to be approximately 5.0% of total produced and purchased throughout the forecast period.

5.0 Purchased Energy and Demand Forecast

Purchased energy is calculated by subtracting Newfoundland Power's normal production from produced and purchased. The Company's normal production for 2021 is 434.8 GWh.[40] Normal production is projected to be 438.4 GWh in 2022.[41] Normal production is projected to be 425.6 GWh in 2023, which reflects the planned refurbishment of the Sandy Brook hydro plant that year.[42]

Newfoundland Power's forecast of native peak demand is determined by applying the average weather-adjusted load factor to the forecast of produced and purchased energy. The Company's purchased demand is then derived by subtracting load curtailment by Newfoundland Power customers and company-owned facilities, and the generation credit approved by the Board.

The Purchased Energy and Demand Forecast is provided in Appendix C.

6.0 Forecast Accuracy

The energy sales forecasts and actual weather-adjusted energy sales for the past 10 years are provided in Appendix D. During this period, differences from forecast have ranged from a high of 1.3% to a low of -1.2%. In 6 of the past 10 years, differences from forecast were 1% or less.

---

[40] On January 29, 2021 Newfoundland Power filed its annual letter to the Board detailing its normal production for 2021, including adjustments made to reflect physical changes to the plants since 2015 and scheduled outages in 2021.

[41] The Base Normal Hydroelectric Production was reviewed in 2020 and reduced slightly from 438.6 GWh to 438.4 GWh. Newfoundland Power is not proposing any planned work at its hydro plants that would result in spillage in 2022. As a result, normal production in 2022 is expected to be consistent with the updated Base Normal Hydroelectric Production.

[42] Normal production of 425.6 GWh in 2023 reflects a Base Normal Hydroelectric Production of 438.4 GWh, less 12.8 GWh of estimated lost production due to planned work at the Sandy Brook hydro plant in 2023.

Newfoundland Power Inc.

Key Economic Indicators[1]
2010 - 2023F

(millions of dollars)

Indicator	Actual				Forecast					
	Average 2010 -2019	2019	2020	Change From 2019	2021	Change From 2020	2022	Change From 2021	2023	Change From 2022
Gross Domestic Product (Millions 2012 $)										
Goods Producing Industries	-0.1%	16,789	16,411	-2.3%	16,765	2.2%	17,927	6.9%	17,466	-2.6%
Service Producing Industries	1.4%	17,286	16,468	-4.7%	17,042	3.5%	17,463	2.5%	17,482	0.1%
Total of All Industries	0.5%	34,075	32,879	-3.5%	33,807	2.8%	35,390	4.7%	34,948	-1.2%
Labour Force ('000s)	-0.1%	259	249	-3.9%	257	3.2%	255	-0.8%	255	0.0%
Employment ('000s)	0.2%	227	214	-5.7%	225	5.1%	226	0.4%	224	-0.9%
Consumer Price Index (2002=1.000)	1.9%	1.393	1.396	0.2%	1.423	2.0%	1.456	2.3%	1.486	2.1%
Household Disposable Income (Millions $)	2.9%	17,293	17,602	1.8%	17,055	-3.1%	17,244	1.1%	17,574	1.9%
Unemployment Rate (%)	N/A[2]	12.3%	14.2%	N/A	12.5%	N/A	11.4%	N/A	12.0%	N/A
Retail Sales (Millions $)	2.1%	8,995	9,029	0.4%	9,086	0.6%	9,282	2.2%	9,537	2.7%
Housing Starts - Units	N/A[3]	945	763	-19.3%	724	-5.1%	692	-4.4%	665	-3.9%
Housing Completions - Units	N/A[3]	975	857	-12.1%	733	-14.5%	689	-6.0%	665	-3.5%
Canadian GDP Deflator (2012=1.000)	1.5%	1.099	1.105	0.5%	1.131	2.4%	1.151	1.8%	1.170	1.7%

[1] The Conference Board of Canada, *Provincial Outlook Medium-Term Economic Forecast* , March 18, 2021.
[2] The unemployment rate declined from 14.7% in 2010 and 12.3% in 2019.
[3] The average number of housing starts and completions over the 2010 to 2019 period were 2,250 units and 2,337 units, respectively.

Newfoundland Power Inc.

Customer and Energy Forecast
2019 - 2023F

		Actual			Forecast		Existing				Proposed			
		2019	2020	Change From 2019	2021	Change From 2020	2022	Change From 2021	2023	Change From 2022	2022	Change From 2021	2023	Change From 2022
Customers														
Domestic														
Regular	1.1	232,572	233,801	0.5%	234,740	0.4%	235,629	0.4%	236,486	0.4%	235,629	0.4%	236,486	0.4%
Seasonal	1.1	1,560	1,459	-6.5%	1,459	0.0%	1,459	0.0%	1,459	0.0%	1,459	0.0%	1,459	0.0%
Total Domestic		234,132	235,260	0.5%	236,199	0.4%	237,088	0.4%	237,945	0.4%	237,088	0.4%	237,945	0.4%
General Service														
0-100 kW (110 kVA)	2.1	22,796	22,871	0.3%	22,925	0.2%	22,977	0.2%	23,026	0.2%	22,977	0.2%	23,026	0.2%
110 kVA (100 kW) - 1000 kVA	2.3	1,267	1,265	-0.2%	1,274	0.7%	1,269	-0.4%	1,269	0.0%	1,269	-0.4%	1,269	0.0%
1000 kVA and Over	2.4	57	59	3.5%	49	-16.9%	57	16.3%	57	0.0%	57	16.3%	57	0.0%
Total General Service		24,120	24,195	0.3%	24,248	0.2%	24,303	0.2%	24,352	0.2%	24,303	0.2%	24,352	0.2%
Street and Area Lighting	4.1	10,793	10,830	0.3%	10,851	0.2%	10,862	0.1%	10,868	0.1%	10,862	0.1%	10,868	0.1%
Total Customers		269,045	270,285	0.5%	271,298	0.4%	272,253	0.4%	273,165	0.3%	272,253	0.4%	273,165	0.3%
Energy Sales (GWh)														
Domestic														
Regular	1.1	3,545.6	3,533.8	-0.3%	3,482.1	-1.5%	3,432.4	-1.4%	3,407.9	-0.7%	3,428.5	-1.5%	3,399.0	-0.9%
Seasonal	1.1	14.2	13.2	-7.0%	12.7	-3.8%	12.9	1.6%	12.9	0.0%	12.9	1.6%	12.9	0.0%
Total Domestic		3,559.8	3,547.0	-0.4%	3,494.8	-1.5%	3,445.3	-1.4%	3,420.8	-0.7%	3,441.4	-1.5%	3,411.9	-0.9%
General Service														
0-100 kW (110 kVA)	2.1	797.6	749.4	-6.0%	772.3	3.1%	796.3	3.1%	796.9	0.1%	796.1	3.1%	796.6	0.1%
110 kVA (100 kW) - 1000 kVA	2.3	1,024.2	990.2	-3.3%	1,032.6	4.3%	1,029.4	-0.3%	1,028.7	-0.1%	1,029.4	-0.3%	1,028.7	-0.1%
1000 kVA and Over	2.4	432.0	410.1	-5.1%	389.1	-5.1%	404.5	4.0%	399.2	-1.3%	404.5	4.0%	399.2	-1.3%
Total General Service		2,253.8	2,149.7	-4.6%	2,194.0	2.1%	2,230.2	1.6%	2,224.8	-0.2%	2,230.0	1.6%	2,224.5	-0.2%
Street and Area Lighting	4.1	33.0	32.3	-2.1%	30.7	-5.0%	27.9	-9.1%	25.2	-9.7%	27.9	-9.1%	25.2	-9.7%
Total Energy Sales		5,846.6	5,729.0	-2.0%	5,719.5	-0.2%	5,703.4	-0.3%	5,670.8	-0.6%	5,699.3	-0.4%	5,661.6	-0.7%
Company Use		11.8	11.4	-3.4%	11.4	0.0%	11.4	0.0%	11.4	0.0%	11.4	0.0%	11.4	0.0%
Losses		314.9	302.4	-4.0%	282.6	-6.5%	300.8	6.4%	299.0	-0.6%	300.5	6.3%	298.5	-0.7%
Produced & Purchased		6,173.3	6,042.8	-2.1%	6,013.5	-0.5%	6,015.6	0.0%	5,981.2	-0.6%	6,011.2	0.0%	5,971.5	-0.7%
Wheeled		120.4	114.6	-4.8%	121.6	6.1%	115.1	-5.3%	109.9	-4.5%	115.1	-5.3%	109.9	-4.5%
Total System Energy		6,293.7	6,157.4	-2.2%	6,135.1	-0.4%	6,130.7	-0.1%	6,091.1	-0.6%	6,126.3	-0.1%	6,081.4	-0.7%

Newfoundland Power Inc.

Purchased Energy and Demand Forecast
2021 - 2023F

	Produced Purchased & Wheeled	Total Wheeled Energy	Total Produced & Purchased (NP Native Peak)			Total Curtailed Demand	NP Produced		Total Purchased	
				(1)	(2) Load	(3)	(4)	(5) Credit		(6)
Year	GWH	GWH	GWH	MW	Factor	MW	GWH	MW	GWH	MW
Existing										
2021	6,135.1	121.6	6,013.5	1,350.792	50.82%	12.0	434.9	118.054	5,578.6	1,220.738
2022	6,130.7	115.1	6,015.6	1,351.264	50.82%	12.0	438.4	118.054	5,577.2	1,221.210
2023	6,091.1	109.9	5,981.2	1,343.537	50.82%	12.0	425.6	118.054	5,555.6	1,213.483
Proposed										
2021	6,135.1	121.6	6,013.5	1,350.792	50.82%	12.0	434.9	118.054	5,578.6	1,220.738
2022	6,126.3	115.1	6,011.2	1,350.275	50.82%	12.0	438.4	118.054	5,572.8	1,220.221
2023	6,081.4	109.9	5,971.5	1,341.358	50.82%	12.0	425.6	118.054	5,545.9	1,211.304

Notes:

1. Native peak is the maximim demand forecast to be served by Newfoundland Power. The 2021 native peak reflects the forecast for the winter period of December 2021 to March 2022.
2. Load Factor is based on an average of 5 year historical (normalized) load factors with 2020 excluded.
3. Based on historical performance of participants plus curtailment of company owned facilities.
4. Normal production for the forecast period is 438.4 GWh adjusted for plant availability and efficiency improvements. Produced for 2021 also includes 0.1 GWh of production at Newfoundland Power's thermal plants.
5. Assumes a generation credit of 118.054 MW.
6. The purchased demand for 2021 reflects the purchased demand from Newfoundland and Labrador Hydro for the winter period of December 2021 to to March 2022 and represents Newfoundland Power's forecast billing demand for 2022.

Newfoundland Power Inc.

Comparison of Forecast Energy Sales to Weather Adjusted Actual Sales

	Forecast Sales[1] (GWh)	Weather Adjusted Actual Sales (GWh)	Difference (GWh)	Difference (%)
2011	5,480.0	5,552.8	72.8	1.3
2012	5,658.1	5,652.2	-5.9	-0.1
2013	5,763.6	5,763.3	-0.3	0.0
2014	5,835.6	5,898.5	62.9	1.1
2015	5,997.2	5,956.6	-40.6	-0.7
2016	5,990.5	5,950.1	-40.4	-0.7
2017	5,992.2	5,922.2	-70.0	-1.2
2018	5,915.0	5,876.1	-38.9	-0.7
2019	5,882.9	5,846.6	-36.3	-0.6
2020	5,793.0	5,729.0	-64.0	-1.1

Notes:

[1] The forecast sales figures are from the annual forecasts prepared in the previous year and were part of the capital budget presentations made to the Board in those years. The 2010, 2013, 2014, 2016, 2017 and 2019 forecasts were the basis for the revenue requirement determinations presented as part of the Company's general rate applications.

Conference Board of Canada
Provincial Medium-Term Forecast
March 2021

Table 1: Key Economic Indicators for Canada, 2021 to 2025
Conference Board of Canada, Provincial Medium Term Forecast
March 2021

	2021	2022	2023	2024	2025
GDP at Market Prices (Millions $)	2,356,096	2,488,332	2,565,975	2,654,528	2,751,739
	7.1	*5.6*	*3.1*	*3.5*	*3.7*
GDP at Market Prices (Millions $2012)	2,083,135	2,162,527	2,193,436	2,233,322	2,279,593
	4.7	*3.8*	*1.4*	*1.8*	*2.1*
GDP at Basic Prices (Millions $2012)	1,969,359	2,046,235	2,076,072	2,114,269	2,158,760
	4.8	*3.9*	*1.5*	*1.8*	*2.1*
Implicit Price Deflator	1.1	1.2	1.2	1.2	1.2
GDP at Basic Prices (2012=1.0)	2.3	1.7	1.7	1.6	1.6
Consumer Price Index (2002=1.0)	1.4	1.4	1.5	1.5	1.5
	1.7	*2.1*	*2.0*	*2.1*	*2.2*
Wages and Salary per Employee (Thousands $)	55.8	56.2	57.4	58.8	60.2
	0.8	*0.8*	*2.2*	*2.4*	*2.4*
Primary Household Income (Millions $)	1,580,085	1,648,991	1,704,693	1,761,217	1,820,410
	5.0	*4.4*	*3.4*	*3.3*	*3.4*
Household Disposable Income (Millions $)	1,362,792	1,393,720	1,434,139	1,479,197	1,525,611
	-1.7	*2.3*	*2.9*	*3.1*	*3.1*
Population of Labour Force Age	31,420	31,781	32,138	32,466	32,795
	1.0	*1.1*	*1.1*	*1.0*	*1.0*
Labour Force (000)	20,436	20,638	20,827	20,994	21,158
	2.5	*1.0*	*0.9*	*0.8*	*0.8*
Employment (000)	18,741	19,291	19,496	19,691	19,888
	3.7	*2.9*	*1.1*	*1.0*	*1.0*
Unemployment Rate	8.3	6.5	6.4	6.2	6.0
Retail Sales (Millions $)	634,698	645,600	661,327	679,262	696,648
	5.3	*1.7*	*2.4*	*2.7*	*2.6*
Housing Starts (Number of Units)	210,657	210,016	207,048	202,086	195,227
	-2.6	*-0.3*	*-1.4*	*-2.4*	*-3.4*

Table 2: Key Economic Indicators for Newfoundland and Labrador, 2021 to 2025
Conference Board of Canada, Provincial Medium Term Forecast
March 2021

	2021	2022	2023	2024	2025
GDP at Market Prices (Millions $)	37,209	40,261	40,849	42,477	44,420
	13.1	*8.2*	*1.5*	*4.0*	*4.6*
GDP at Market Prices (Millions $2012)	33,807	35,390	34,948	35,819	36,808
	2.8	*4.7*	*-1.2*	*2.5*	*2.8*
GDP at Basic Prices (Millions $2012)	31,997	33,384	32,977	33,809	34,759
	3.0	*4.3*	*-1.2*	*2.5*	*2.8*
Implicit Price Deflator	1.1	1.1	1.2	1.2	1.2
GDP at Basic Prices (2012=1.0)	10.2	3.4	2.7	1.5	1.8
Consumer Price Index (2002=1.0)	1.4	1.5	1.5	1.5	1.6
	2.0	*2.3*	*2.1*	*2.3*	*2.2*
Wages and Salary per Employee (Thousands $)	55.7	57.3	58.5	59.7	60.9
	-0.9	*2.9*	*2.1*	*2.0*	*2.1*
Primary Household Income (Millions $)	18,961	19,748	20,158	20,636	21,102
	3.8	*4.1*	*2.1*	*2.4*	*2.3*
Household Disposable Income (Millions $)	17,055	17,244	17,574	18,024	18,529
	-3.1	*1.1*	*1.9*	*2.6*	*2.8*
Population of Labour Force Age	443	440	437	435	433
	-0.6	*-0.8*	*-0.6*	*-0.4*	*-0.4*
Labour Force (000)	257	255	255	254	254
	3.1	*-0.7*	*-0.1*	*-0.1*	*-0.1*
Employment (000)	225	226	224	224	225
	5.1	*0.6*	*-0.8*	*0.1*	*0.1*
Unemployment Rate	12.5	11.4	12.0	11.8	11.6
Retail Sales (Millions $)	9,086	9,282	9,537	9,782	10,039
	0.6	*2.2*	*2.7*	*2.6*	*2.6*
Housing Starts (Number of Units)	724	692	665	638	611
	-5.1	*-4.5*	*-3.9*	*-4.1*	*-4.3*

Cost of Service Study

May 2021

Table of Contents

1.0 General

Cost of service studies are conducted on a regular basis to evaluate the reasonableness of cost recovery by class of service and as a step in the traditional process for establishing Newfoundland Power Inc.'s ("Newfoundland Power" or the "Company") customer rates.

In Newfoundland Power's *2003/2004 General Rate Application*, the Company presented detailed evidence on its cost of service study methodology. Through a mediation process, the parties at the hearing recommended the approval of the cost of service study methodology. In Order No. P.U. 19 (2003), the Board approved the recommendations as presented in the evidence and the Mediation Report.

In Order No. P.U. 32 (2007), the Board stated that it was satisfied that Newfoundland Power's cost of service study and methodology, along with the Marginal Cost Study, were appropriate to be used in establishing 2008 customer rates.

At Newfoundland Power's 2010, 2013/2014, 2016/2017, and 2019/2020 general rate applications, the results of the Company's cost of service studies were accepted for use in establishing customer rates.

2.0 2019 *Pro Forma* Cost of Service Study

The Company has completed a 2019 *pro forma* Cost of Service Study (the "Cost of Service Study"). The detailed results of the Cost of Service Study are shown in Appendix A.

The Cost of Service Study is based on actual costs and revenue incurred in 2019, adjusted to reflect the increase in purchased power costs as a result of Newfoundland and Labrador Hydro's ("Hydro") *2017 General Rate Application*, including Rate Stabilization Plan ("RSP") changes, effective October 1, 2019, and associated changes in Newfoundland Power's customer rates.

2.1 Pro Forma Adjustments

The adjustments made to 2019 costs reflect changes to Newfoundland Power's purchased power costs resulting from Hydro's *2017 General Rate Application* and are based on Hydro's 2019 test year.[1] *Pro forma* adjustments to reflect Newfoundland Power's purchased power costs include:

(i) Increasing the actual 2019 purchased power expense by $59,913,000.[2]

(ii) Adjusting the actual revenue from base rates per Table 1:

Table 1:
2019 *Pro Forma* Revenue Adjustments[3]

Domestic	9.10%
General Service Rate #2.1	9.10%
General Service Rate #2.3	9.10%
General Service Rate #2.4	9.10%
Street and Area Lighting[4]	3.15%
Total *Pro Forma* Revenue Adjustment	8.96%

(iii) Decreasing revenue from the Rate Stabilization Account ("RSA") rate stabilization adjustment by -82.3% to reflect a 2019 rate stabilization adjustment change from 0.243 ¢/kWh to 0.043 ¢/kWh.[5]

(iv) Adjusting the functional classification of the purchased power costs to reflect the functional classification of the costs allocated to Newfoundland Power from Hydro's 2019 test year cost of service study.

(v) Adjusting the classification of hydro production to match the system load factor as used in Hydro's 2019 test year cost of service study.

---

1 Hydro's *2017 GRA Compliance Application* was approved by the Board in Order No. P.U. 30 (2019). Hydro's 2019 test year cost of service study was filed as Exhibit 14 of Hydro's application.

2 See Newfoundland Power's *Application for October 1, 2019 Customer Rates*, September 13, 2019, Schedule 1, Page 4, Table 1. The application was approved in Order No. P.U. 31 (2019).

3 The increase in overall revenue from customer rates resulting from the *pro forma* adjustment is 8.96% and represents the increase in purchase power expense of $59,913,000 compared to Newfoundland Power's revenue from rates in 2019 of $666,001,000 and forfeited discounts in 2019 of $2,892,000 ($59,913,000 / ($666,001,000 + $2,892,000) x 100% = 8.96%.

4 Based upon the cost of service study underpinning current base rates, purchased power costs comprise 66.8% of Newfoundland Power's overall cost of providing electrical service, but only 23.5% of the cost of providing Street and Area Lighting Service (23.5% / 66.8% = 35.2%). As a result, the *pro forma* purchased power adjustment to Street and Area Lighting revenue is approximately 35.2% of the overall increase (8.96% x 35.2% = 3.15%).

5 The rate stabilization adjustment that applied to customer rates from January 1, 2019 to September 30, 2019 was 0.285 ¢/kWh. The rate stabilization adjustment that applied to customer rates from October 1, 2019 to December 31, 2019 was 0.043 ¢/kWh. The effective rate stabilization adjustment that applied to customer rates from January 1, 2019 to December 31, 2019 was 0.243 ¢/kWh and is calculated as total RSA billings for 2019 divided by total energy sales for 2019 ($14,180,163 / 5,846,583,000 GWh = 0.243 ¢/kWh.). Newfoundland Power's rate stabilization adjustment of 0.043 ¢/kWh was approved by the Board in Order No. PU. 31 (2019).

2.2 Cost of Service Study Updates

The Cost of Service Study incorporates results from 4 specific studies. These studies, which are updated approximately every 5 years, were updated based on 2019 actual costs and the results are included in the 2019 *pro forma* Cost of Service Study. The 4 studies are:

(i) Customer Weighting Factor Study;
(ii) Minimum System Analysis;
(iii) Transformer Zero Intercept Analysis; and
(iv) General Plant Allocation Study.

Table 2 shows the impact that, in aggregate, the updates to the 4 studies had on the Company's revenue-to-cost ratios.

Table 2:
Revenue-to-Cost Ratios
(%)

	With Old Studies	With New Studies	Variance
Domestic	96.7	96.6	(0.1)
General Service			
(0-100kW)	108.0	108.5	0.5
(110-1000kVA)	106.2	106.8	0.6
(1000kVA and Over)	101.9	102.3	0.4
Street Lighting	107.9	105.3	(2.6)
Total	**100.0**	**100.0**	**0.0**

3.0 Cost of Service Study Results

Appendix A shows the detailed results of the Cost of Service Study.

The results of the Cost of Service Study have been divided into the following 5 groups of schedules:

Group 1: Results, pages 2 to 14 of 43.

Group 2: Functional Classification of Rate Base, pages 15 to 22 of 43.

Group 3: Functional Classification of Expenses, pages 23 to 29 of 43.

Group 4: Determination of Class Allocation Factors, pages 30 to 38 of 43.

Group 5: Miscellaneous Schedules, pages 39 to 43 of 43.

3.1 Group 1: Results

Schedule 1.1 shows the major components that make up the total cost of service (excluding rate stabilization costs, municipal taxes and the rural deficit funding). The major components include purchased power expenses,[6] operating and maintenance expenses, depreciation expenses, expense credits and return and taxes. The schedule shows the breakdown of these cost components into the various functional classification groups used in the study. Expense credits include revenue that is either not generated from rates or is recovered through the RSA and is associated with particular functional classification groups.

Schedule 1.2 provides the cost by each functional classification group and the amount allocated to each class of service. The costs do not include rate stabilization costs, municipal taxes or the rural deficit funding.

Schedule 1.3 shows the total cost of service by class of service including rate stabilization costs, municipal taxes and the rural deficit funding. The schedule also subtracts other revenue from total costs to provide a column representing the total costs recovered from final customer rates.

Schedule 1.4 shows the revenue attributed to each class of service. The schedule shows all the components that make up the total billings to customers plus other revenue. The other revenue amount excludes the revenue treated as expense credits in Schedule 1.1. Other revenue is attributed to each class of service based on the total revenue from base rates by class.

Schedule 1.5 compares the revenue by class to the cost by class and shows the revenue-to-cost ratios for each class of service. The costs from Schedule 1.3 and the revenues from Schedule 1.4 are used to compute the revenue-to-cost ratios.

Schedule 1.6 provides rate loaders that, when applied to the classified cost components (demand, energy, customer and specifically assigned costs), result in costs that can be compared to final customer rate components. The rate loaders are applied to each of the classified cost components. The RSA loader is added to the classified energy costs.

Schedule 1.7 expresses the cost of service in terms of unit costs. The unit costs provided are the $ per kW/kVA for demand costs, ¢/kWh for energy costs, and $/bill for customer-related costs. Also provided is a breakdown of demand and customer costs in ¢/kWh and an overall total cost expressed in terms of ¢/kWh.

3.2 Group 2: Functional Classification of Rate Base

Schedule 2.1 shows the original cost of the Company's fixed assets and its breakdown by the various functional classification categories. The total cost is based on the average amount of fixed assets employed during the year.

Schedule 2.2 shows the average accumulated depreciation and its breakdown into functional classification categories.

---

[6] The purchased power expense excludes the portion of the expense that is attributed to funding Hydro's rural deficit.

Schedule 2.3 shows the net contributions in aid of construction ("CIAC"). The net CIAC is the total CIAC received from customers and governments, less the CIAC amortized to date.

Schedule 2.4 shows the average rate base. The average rate base includes the total net utility plant, deductions from rate base and additions to rate base.[7] The net utility plant is the original cost of the fixed assets (Schedule 2.1) less the accumulated depreciation (Schedule 2.2).

3.3 Group 3: Functional Classification of Expenses

Schedule 3.1 shows the Company's expenses, both regulated and non-regulated, by cost of service expense category.

Schedule 3.2 shows the functional classification of the Company's expenses by expense category as follows:

1. Purchased Power Expense.[8]

2. Direct Operating and Maintenance Expenses. These expenses include those internal costs that can be directly placed into functional groups.

3. General System Expense. These expenses include costs related to general operations, communications and the system control center.

4. Administration and General Expenses. These expenses include the costs of administration, human resources, information systems, finance and regulatory costs.

5. CDM Costs. These expenses include CDM general costs, CDM program costs and the costs associated with the Curtailable Service Option.

Schedule 3.3 shows the breakdown of depreciation expense, net of CIAC amortization, into functional classification categories.

---

[7] The deductions from average rate base include the net CIAC (Schedule 2.3), customer security deposits, post-retirement benefits liability, future income taxes, and the demand management incentive liability. The additions to average rate base include average deferred charges (mostly pension costs), unamortized cost recovery deferrals, customer financing programs, the balance in the weather normalization reserve, cash working capital allowance, and materials and supplies allowance.

[8] The expense shown in the schedule excludes the portion of the purchased power cost associated with funding Hydro's rural deficit.

3.4 Group 4: Determination of Class Allocation Factors

Schedule 4.1 shows the customer statistics used to develop the allocation factors. The customer statistics include: the number of customers; total energy sales; total billing demand (where applicable); the estimated class load factors based on non-coincident peak ("NCP"); and the estimated class load factors based on coincident peak ("1 CP"). Schedule 4.1 also shows the estimated class demands at time of class peak (NCP) and the estimated class demands at time of Hydro's system peak (1 CP).

Schedule 4.2 shows the loss factors that are used as an input in calculating the energy and demand allocation factors.

Schedule 4.3 shows the development of the allocation factors for customer-related costs. The allocation factor for each type of customer cost is based on a weighting factor and the number of customers. An allocation factor of 0.0% occurs in a number of instances, such as the allocation factor used to allocate customer-related secondary costs to transmission customers. This reflects the concept that a transmission customer (i.e. a customer that takes their electricity supply from the transmission system) is not responsible for any of the cost of the distribution secondary or distribution primary system.

Schedule 4.4 shows the development of the secondary, primary and transmission allocation factors for energy-related costs. The allocation factors are based on energy sales and losses. Three separate allocation factors are required to ensure that within the cost of service study, a transmission customer is not allocated any of the cost of the distribution secondary or primary system and that a distribution primary customer is not allocated any of the cost of the distribution secondary system.

Schedule 4.5 shows the development of the NCP demand allocation factors. The allocation factors are based on the estimated class peak and the loss factors shown in Schedule 4.1 and Schedule 4.2 respectively. The table shows 3 sets of allocation factors that are used when allocating the demand-related cost associated with either the secondary, primary or transmission levels.

Schedule 4.6 shows the development of the 1 CP demand allocation factor. The allocation factors are based on the estimated class demand at time of system peak and the loss factors shown in Schedule 4.1 and Schedule 4.2, respectively. The table shows 3 sets of allocation factors that are used when allocating the demand-related cost associated with either the secondary, primary or transmission levels.

3.5 Group 5: Miscellaneous Schedules

Schedule 5.1 shows the functional classification splits used in the Cost of Service Study. The input data was primarily derived from a variety of functionalization and classification studies. The sources of each functionalization and classification split are detailed in the footnotes in Schedule 5.1.

Schedule 5.2 shows the reconciliation of the total expenses used in the Cost of Service Study to the *2019 Annual Report* to the Board.

Schedule 5.3 shows the reconciliation of the total revenue used in the Cost of Service Study to the *2019 Annual Report* to the Board.

Schedule 5.4 shows the reconciliation of the total return and taxes used in the Cost of Service Study to the *2019 Annual Report* to the Board.

Cost of Service Study

Newfoundland Power Inc.
Pro Forma 2019 Cost of Service Study

Table of Contents

Notes:
1 - Within the Schedules rows and columns may not add due to rounding.

Newfoundland Power Inc.
Pro Forma 2019 Cost of Service Study

FUNCTIONAL CLASSIFICATION OF THE COST OF SERVICE
(All numbers are times $1,000)

Line No.	Category	Total	Produced & Purchased Demand	Produced & Purchased Energy	Transmission Demand	Distribution: Substation Demand	Distribution: Primary Demand	Distribution: Primary Customer	Distribution: Transformers Demand	Distribution: Transformers Customer	Distribution: Secondary Demand	Distribution: Secondary Customer	Distribution: Services Customer	Distribution: Meters Customer	Distribution: St. Lighting Customer	Customer Acc. & Cust. Serv.	Customer Specific	Revenue Related
		A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
1	Purchase Power	443,011	185,743	257,267	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Operating and Maintenance	72,356	5,342	9,031	5,567	5,483	8,446	4,959	1,977	769	2,112	1,240	6,324	679	4,141	13,690	35	2,565
3	Depreciation	62,066	4,526	3,338	8,121	6,029	11,861	6,966	3,817	1,484	2,965	1,742	3,800	2,667	2,526	2,170	53	0
	Expense Credits																	
	Wheeling Revenues																	
4	Transmission	503	0	0	503	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Distribution	262	0	0	0	0	165	97	0	0	0	0	0	0	0	0	0	0
6	Joint Use Revenue	2,275	0	0	0	0	1,147	673	0	0	287	168	0	0	0	0	0	0
7	Revenue from Temp. Service and Reconnects	195	0	0	0	0	0	0	0	0	0	0	195	0	0	0	0	0
8	Customer Service Fees	260	0	0	0	0	0	0	0	0	0	0	0	0	0	260	0	0
9	RSA Transfer - Energy Supply Cost Variance	(3,326)	0	(3,326)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	RSA Transfer - CDM Revenue Deferral	4,597	0	4,597	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	Total Expense Credits	4,766	0	1,271	503	0	1,311	770	0	0	287	168	195	0	0	260	0	0
12	Subtotal Expenses	572,667	195,611	268,366	13,184	11,512	18,996	11,155	5,794	2,253	4,790	2,813	9,929	3,346	6,667	15,599	88	2,565
13	Return and Taxes	99,650	7,599	7,646	13,455	12,284	18,469	10,837	7,451	2,895	4,617	2,709	3,764	2,780	2,852	2,138	92	62
14	Total Cost of Service (Excluding RSA, MTA, Rural Deficit)	672,317	203,210	276,012	26,639	23,796	37,465	21,992	13,245	5,148	9,408	5,522	13,693	6,126	9,519	17,737	180	2,626

Newfoundland Power Inc.
Pro Forma 2019 Cost of Service Study

FUNCTIONAL CLASSIFICATION OF THE COST OF SERVICE

Line No.	Category	
1	Purchase Power	Taken from Schedule 3.2, Line 4. (Excludes the Rural Deficit of $61,762,933)
2	Operating and Maintenance	Taken from Schedule 3.2, Line 37 less Line 4. (Excludes non-regulated expenses of $3,576,488)
3	Depreciation	Taken from Schedule 3.3, Line 20
	Expense Credits	
	Wheeling Revenues	
4	Transmission	Allocated based on functional classification of Transmission O&M expenses excluding specifically assigned (Schedule 3.2, Line 7).
5	Distribution	Based on the functional classification of Primary Distribution (Schedule 3.2, Line 12, Columns F & G).
6	Joint Use Revenue	Based on the functional classification of Poles, Lines and Fittings (Schedule 3.2, Line 12).
7	Revenue from Temp. Service and Reconnects	Based on functional classification of Services (Schedule 3.2, Line 13).
8	Customer Service Fees	Functional classification based on 100% Customer Service/ Customer Accounting.
9	RSA Transfer - Energy Supply Cost Variance	Classified 100% to Energy
10	RSA Transfer - CDM Revenue Deferral	Classified 100% to Energy
11	Total Expense Credits	Sum of lines 4 through 10.
12	Subtotal Expenses	Total of Lines 1, 2, and 3, less Line 11. (See Schedule 5.2 for the reconcillation to Total Company Expenses as Reported.)
13	Return and Taxes	Functional Classification based on Total Average Rate Base, Schedule 2.4, Line 38. (See Schedule 5.4 for the reconcillation to total Company Return and Taxes as Reported.)
14	Total Cost of Service (Excluding RSA, MTA, Rural Deficit)	Total of Lines 12 and 13.

Newfoundland Power Inc.
Pro Forma 2019 Cost of Service Study

ALLOCATION OF THE COST OF SERVICE TO CLASS OF SERVICE
Total Cost of Service excludes RSA, MTA and Rural Deficit (All numbers are times $1,000)

Line No.	Class of Service	Rate Code	Total	Produced & Purchased Demand A	Produced & Purchased Energy B	Transmission Demand C	Distribution: Substation Demand D	Primary: Demand E	Primary: Customer F	Transformers: Demand G	Transformers: Customer H	Secondary: Demand I	Secondary: Customer J	Services Customer K	Meters Customer L	St. Lighting Customer M	Customer Acc. & Cust. Serv. N	Specifically Assigned O	Revenue Related P
	Allocation Factors Used ==>			Transmission 1CP	Transmission Energy	Transmission 1CP	Primary NCP	Primary NCP	Weighted Customers	Secondary NCP	Weighted Customers	Secondary NCP	Weighted Customers	Weighted Customers	Weighted Customers		Weighted Customers		Revenue
	DOMESTIC																		
1	Domestic Regular	1.1	97,674	26,985	35,463	3,537	3,574	5,627	5,877	2,098	1,311	1,490	1,476	3,779	1,176	0	4,910	0	368
2	Domestic All Electric	1.1	345,153	111,758	132,690	14,650	12,005	18,902	13,256	7,048	2,957	5,006	3,330	8,523	2,653	0	11,074	0	1,301
3	Total Domestic	1.1	442,827	138,743	168,153	18,188	15,579	24,529	19,133	9,146	4,269	6,496	4,806	12,302	3,830	0	15,984	0	1,669
	GENERAL SERVICES																		
4	(0-10 kW)	2.1	11,520	2,458	4,065	322	346	545	999	203	268	144	251	642	520	0	710	0	47
5	(10-100 kW)	2.1	72,945	22,193	33,613	2,909	2,769	4,360	865	1,626	347	1,155	217	667	1,246	0	665	0	312
6	Total (0-100 kW)	2.1	84,465	24,651	37,678	3,231	3,116	4,905	1,864	1,829	615	1,299	468	1,310	1,766	0	1,374	0	359
	(110-1000 kVA)	2.3																	
7	Primary (110-350 kVA)		1,162	350	611	46	46	73	1	0	0	0	0	0	27	0	1	0	5
8	Secondary (110-350 kVA)		45,705	13,450	23,340	1,763	1,784	2,809	79	1,047	53	744	20	81	279	0	60	0	197
9	Transmission (350-1000 kVA)		53	16	29	2	0	0	0	0	0	0	0	0	5	0	0	0	0
10	Primary (350-1000 kVA)		9,041	2,776	4,846	364	368	580	3	0	0	0	0	0	63	0	3	0	38
11	Secondary (350-1000 kVA)		37,833	11,243	19,509	1,474	1,491	2,348	19	875	13	622	5	0	67	0	15	0	152
12	Total (110-1000 kVA)	2.3	93,794	27,835	48,336	3,649	3,690	5,809	103	1,923	65	1,366	25	81	441	0	79	0	392
	(1000 kVA and Over)	2.4																	
13	Transmission		1,393	420	808	55	0	0	0	0	0	0	0	0	6	0	0	98	6
14	Primary		22,455	6,635	12,599	870	820	1,291	2	0	0	0	0	0	66	0	2	82	89
15	Secondary		12,678	3,642	6,874	477	450	709	2	264	2	188	1	0	17	0	2	0	51
16	Total (1000 kVA and Over)	2.4	36,526	10,697	20,281	1,402	1,270	1,999	5	264	2	188	1	0	89	0	4	180	146
17	**STREET LIGHTING**	4.1	14,705	1,284	1,564	168	141	222	887	83	198	59	223	0	0	9,519	296	0	60
18	Total		672,317	203,210	276,012	26,639	23,796	37,465	21,992	13,245	5,148	9,408	5,522	13,693	6,126	9,519	17,737	180	2,626

Newfoundland Power Inc.
Pro Forma 2019 Cost of Service Study

ALLOCATION OF THE COST OF SERVICE TO CLASS OF SERVICE

NOTES:

Line No.	Category	
18	Total	Total Cost of Service shown in Schedule 1.1, Line 14

Column

A	Produced and Purchased Demand	Transmission demand Allocator for 1CP taken From Schedule 4.6, Column L.
B	Produced and Purchased Energy	Transmission Energy Allocator taken From Schedule 4.4, Column L.
C	Transmission Demand	Transmission demand Allocator for 1CP taken From Schedule 4.6, Column L.
D	Distribution Substation Demand	Primary demand Allocator for NCP taken from Schedule 4.5, Column H.
E	Distribution Primary Demand	Primary demand Allocator for NCP taken from Schedule 4.5, Column H.
F	Distribution Primary Customer	Primary Lines Customer Allocator taken from Schedule 4.3, Column G.
G	Distribution Transformer Demand	Secondary demand Allocator for NCP taken from Schedule 4.5, Column D.
H	Distribution Transformer Customer	Transformer Customer Allocator taken from Schedule 4.3, Column M.
I	Distribution Secondary Demand	Secondary demand Allocator for NCP taken from Schedule 4.5, Column D.
J	Distribution Secondary Customer	Secondary Lines Customer Allocator taken from Schedule 4.3, Column J.
K	Distribution Services Customer	Service Drop Allocator taken from Schedule 4.3, Column P.
L	Distribution Meters Customer	Meters Allocator taken from Schedule 4.3, Column S.
M	Distribution Street Lighting Customer	All Allocated to Street Lighting Rate Class.
N	Cust. Accounting and Cust. Services	Customer Allocator taken from Schedule 4.3, Column D.
O	Specifically Assigned	Total cost are allocated to class based on the amount of fixed plant dedicated to supplying single customers and the class which those customers belong.
P	Revenue Related	Total cost is allocated based on revenue from class plus RSA and MTA revenue, Column I, from Schedule 1.4.

Newfoundland Power Inc.
Pro Forma 2019 Cost of Service Study

TOTAL ALLOCATION OF THE COST OF SERVICE
(All dollars are times 1,000)

Line No.	Class of Service	Rate Code	Energy A	Demand B	Customer C	Street Lighting D	Specifically Assigned E	Revenue Related Expenses F	Total before RSA, MTA and Rural Deficit G	Allocated Rural Subsidy H	MTA I	RSA J	Total Cost to Serve K	Allocation of Other Revenue L	Total Cost Recovered in Final Rates M
	DOMESTIC														
1	Domestic Regular	1.1	$35,463	$43,313	$18,530	$0	$0	$368	$97,674	$8,973	$2,456	$321	$109,423	$739	$108,684
2	Domestic All Electric	1.1	$132,690	$169,369	$41,793	$0	$0	$1,301	$345,153	$31,708	$8,690	$1,217	$386,767	$2,613	$384,154
3	Total Domestic	1.1	$168,153	$212,681	$60,323	$0	$0	$1,669	$442,827	$40,681	$11,146	$1,538	$496,191	$3,352	$492,838
	GENERAL SERVICE														
4	(0-10 kW)	2.1	$4,065	$4,018	$3,390	$0	$0	$47	$11,520	$1,058	$313	$37	$12,928	$94	$12,834
5	(10-100 kW)	2.1	$33,613	$35,013	$4,008	$0	$0	$312	$72,945	$6,701	$2,083	$309	$82,038	$626	$81,411
6	Total (0-100 kW)	2.1	$37,678	$39,031	$7,398	$0	$0	$359	$84,465	$7,759	$2,395	$346	$94,966	$720	$94,246
	(110-1000 kVA)	2.3													
7	Primary (110-350 kVA)		$611	$516	$30	$0	$0	$5	$1,162	$107	$32	$6	$1,306	$10	$1,296
8	Secondary (110-350 kVA)		$23,340	$21,597	$571	$0	$0	$197	$45,705	$4,199	$1,314	$211	$51,428	$395	$51,034
9	Transmission (350-1000 kVA)		$29	$18	$6	$0	$0	$0	$53	$5	$2	$0	$60	$0	$59
10	Primary (350-1000 kVA)		$4,846	$4,088	$69	$0	$0	$38	$9,041	$831	$254	$44	$10,170	$76	$10,094
11	Secondary (350-1000 kVA)		$19,509	$18,053	$118	$0	$0	$152	$37,833	$3,476	$1,016	$177	$42,501	$305	$42,196
12	Total (110-1000 kVA)	2.3	$48,336	$44,272	$794	$0	$0	$392	$93,794	$8,616	$2,617	$438	$105,466	$787	$104,679
	(1000 kVA and Over)	2.4													
13	Transmission		$808	$475	$6	$0	$98	$6	$1,393	$128	$38	$6	$1,565	$11	$1,554
14	Primary		$12,599	$9,615	$70	$0	$82	$89	$22,455	$2,063	$598	$112	$25,228	$180	$25,048
15	Secondary		$6,874	$5,730	$23	$0	$0	$51	$12,678	$1,165	$340	$61	$14,243	$102	$14,141
16	Total (1000 kVA and Over)	2.4	$20,281	$15,820	$99	$0	$180	$146	$36,526	$3,356	$976	$179	$41,036	$293	$40,743
17	**STREET LIGHTING**	4.1	$1,564	$1,958	$1,604	$9,519	$0	$60	$14,705	$1,351	$403	$14	$16,472	$122	$16,351
18	Total		$276,012	$313,762	$70,218	$9,519	$180	$2,626	$672,316	$61,763	$17,537	$2,514	$754,130	$5,274	$748,856

Newfoundland Power Inc.
Pro Forma 2019 Cost of Service Study

TOTAL ALLOCATION OF THE COST OF SERVICE

NOTES:

Column

A	Energy cost taken from Schedule 1.2, Column B.
B	Demand cost taken from Schedule 1.2, as the sum of Columns A, C, D, E, G and I.
C	Customer cost taken from Schedule 1.2, as the sum of Columns F, H, J, K, L and N.
D	Direct Street Lighting Cost taken from Schedule 1.2, Column M.
E	Specifically assigned cost taken from Schedule 1.2, Column O.
F	Revenue Related Expenses taken from Schedule 1.2, Column P.
G	Sum of Columns A through F.
H	Rural Surcharge allocated to Class based on total cost before Rural Deficit, RSA & MTA, Column G.
I	MTA cost taken as equal to MTA revenue as taken from Schedule 1.4 Column G.
J	RSA cost taken as equal to revenue from RSA factor from Schedule 1.4 Column F.
K	Sum of Columns G through J.
L	Taken from the sum of Schedule 1.4, Column C.
M	Column K less Column L.

Newfoundland Power Inc.
Pro Forma 2019 Cost of Service Study

REVENUE BY CLASS OF SERVICE
(All dollars are times 1,000)

Line No.	Class of Service	Rate Code	Revenue from Base Rates: Base Rates A	Revenue from Base Rates: Forfeited Discounts B	Allocation of Other Revenue C	Remove Rural Subsidy D	Total Before Rural Subsidy E	RSA Revenue F	MTA Revenue G	Rural Subsidy H	Total Revenue + RSA & MTA I	Total Revenue from Final Rates J
	DOMESTIC											
1	Domestic Regular	1.1	101,562	531	739	(8,973)	93,859	321	2,456	8,973	105,609	104,870
2	Domestic All Electric	1.1	359,212	1,940	2,613	(31,708)	332,058	1,217	8,690	31,708	373,672	371,059
3	Total Domestic		460,774	2,471	3,352	(40,681)	425,918	1,538	11,146	40,681	479,281	475,929
	GENERAL SERVICE											
4	(0-10 kW)	2.1	12,943	56	94	(1,058)	12,035	37	313	1,058	13,443	13,349
5	(10-100 kW)	2.1	86,235	309	626	(6,701)	80,469	309	2,083	6,701	89,562	88,935
6	Total (0-100 kW)	2.1	99,178	365	720	(7,759)	92,504	346	2,395	7,759	103,005	102,284
	(110-1000 kVA)	2.3										
7	Primary (110-350 kVA)		1,333	4	10	(107)	1,240	6	32	107	1,385	1,375
8	Secondary (110-350 kVA)		54,446	125	395	(4,199)	50,767	211	1,314	4,199	56,491	56,096
9	Transmission (350-1000 kVA)		66	1	0	(5)	62	0	2	5	69	68
10	Primary (350-1000 kVA)		10,537	12	76	(831)	9,795	44	254	831	10,924	10,847
11	Secondary (350-1000 kVA)		42,100	89	305	(3,476)	39,019	177	1,016	3,476	43,688	43,383
12	Total (110-1000 kVA)	2.3	108,483	231	787	(8,616)	100,884	438	2,617	8,616	112,556	111,770
	(1000 kVA and Over)	2.4										
13	Transmission		1,582	4	11	(128)	1,469	6	38	128	1,641	1,630
14	Primary		24,775	35	180	(2,063)	22,927	112	598	2,063	25,699	25,520
15	Secondary		14,062	49	102	(1,165)	13,048	61	340	1,165	14,614	14,511
16	Total (1000 kVA and Over)	2.4	40,419	88	293	(3,356)	37,445	179	976	3,356	41,954	41,661
17	**STREET LIGHTING**	4.1	16,796	0	122	(1,351)	15,567	14	403	1,351	17,335	17,213
18	Total		725,651	3,155	5,274	(61,763)	672,317	2,514	17,537	61,763	754,131	748,857

Newfoundland Power Inc.
Pro Forma 2019 Cost of Service Study

REVENUE BY CLASS OF SERVICE

NOTE:
Column
A - From Booked Revenue and Bill Frequency Analysis, adjusted for October 1, 2019 rate change.
B - From Booked Revenue and Bill Frequency Analysis, adjusted for October 1, 2019 rate change.
C - Includes Other Revenue as reported in Return 14 of the Annual Report to the Board ($13,122) less Expense Credits in Schedule 1.1 lines 4 through 8 ($3,495) and Other Contract Expenses from Return 20 of the Annual Report to the Board ($4,353).
D - The rural deficit cost is removed from revenue by allocating the cost to each customer class based on class cost as shown on Schedule 1.3 Column H.
E - Total of Columns A through D.
F - From actual MTA booked and Bill Frequency Analysis, adjusted for October 1, 2019 rate change.
G - From actual RSA booked and Bill Frequency Analysis, , adjusted for October 1, 2019 rate change.
H - From Column D.
I - Total of Columns E through H.
J - Column I less Column C.

Newfoundland Power Inc.
Pro Forma 2019 Cost of Service Study

REVENUE TO COST RATIO
Including RSA, MTA and Rural Subsidy
(All dollars are times 1,000)

Line No.	Class of Service	Rate	Revenue from Final Rates A	Costs B	Revenue to Cost Ratio C
1	**DOMESTIC**	1.1	475,929	492,838	96.6%
	GENERAL SERVICE				
2	(0-100 kW)	2.1	102,284	94,246	108.5%
3	(110 - 1000 kVA)	2.3	111,770	104,679	106.8%
4	(1000 kVA and Over)	2.4	41,661	40,743	102.3%
5	**STREET LIGHTING**	4.1	17,213	16,351	105.3%
6	Total		748,857	748,856	100.0%

Column
A Revenue from Schedule 1.4, Column J.
B Costs from Schedule 1.3, Column M.
C Column A divided by Column B.

Newfoundland Power
Pro Forma 2019 Cost of Service Study

CLASSIFIED COST LOADERS BY CLASS

Line No.	Class of Service	Rate Code	% Loader to be assigned to each Classified Cost Component							RSA Cost Loader (cents/kWh)		
			Rural Subsidy A	Revenue Related Costs B	Non-Rate Revenue Recovery C	MTA D	Total Costs in Loader E	Total Classified Costs F	% Rate Loader G	RSA H	Sales MWh I	RSA cents/kWh J
	DOMESTIC											
1	Domestic Regular	1.1	8,973	368	(739)	2,456	11,058	97,306	11%	321	750,728	0.04
2	Domestic All Electric	1.1	31,708	1,301	(2,613)	8,690	39,085	343,852	11%	1,217	2,808,986	0.04
3	Total Domestic	1.1	40,681	1,669	(3,352)	11,146	50,143	441,158	11%	1,538	3,559,714	0.04
	GENERAL SERVICE											
4	(0-10 kW)	2.1	1,058	47	(94)	313	1,324	11,473	12%	37	86,057	0.04
5	(10-100 kW)	2.1	6,701	312	(626)	2,083	8,470	72,633	12%	309	711,568	0.04
6	Total (0-100 kW)	2.1	7,759	359	(720)	2,395	9,793	84,107	12%	346	797,625	0.04
	(110-1000 kVA)	2.3										
7	Primary (110-350 kVA)		107	5	(10)	32	134	1,157	12%	6	13,045	0.04
8	Secondary (110-350 kVA)		4,199	197	(395)	1,314	5,314	45,508	12%	211	494,090	0.04
9	Transmission (350-1000 kVA)		5	0	(0)	2	6	53	12%	0	628	0.05
10	Primary (350-1000 kVA)		831	38	(76)	254	1,046	9,003	12%	44	103,392	0.04
11	Secondary (350-1000 kVA)		3,476	152	(305)	1,016	4,338	37,681	12%	177	413,006	0.04
12	Total (110-1000 kVA)	2.3	8,616	392	(787)	2,617	10,839	93,402	12%	438	1,024,161	0.04
	(1000 kVA and Over)	2.4										
13	Transmission		128	6	(11)	38	160	1,387	12%	6	17,684	0.03
14	Primary		2,063	89	(180)	598	2,570	22,366	11%	112	268,778	0.04
15	Secondary		1,165	51	(102)	340	1,453	12,627	12%	61	145,517	0.04
16	Total (1000 kVA and Over)	2.4	3,356	146	(293)	976	4,184	36,380	12%	179	431,979	0.04
17	**STREET LIGHTING**	4.1	1,351	60	(122)	403	1,693	14,644	12%	14	33,104	0.04
18	Total		61,763	2,626	(5,274)	17,537	76,652	669,690	11%	2,514	5,846,583	0.04

Newfoundland Power Inc.
Pro Forma 2019 Cost of Service Study

CLASSIFIED COST LOADERS BY CLASS

NOTE:
Column
A - See Schedule 1.3, Column H.
B - See Schedule 1.3, Column F.
C - See Schedule 1.3, Column L. (Negative).
D - See Schedule 1.3, Column I.
E - Total of Columns A through D.
F - See Schedule 1.3, Sum of Columns A through E.
G - Column E divided by Column F.
H - See Schedule 1.3, Column J.
I - See Schedule 4.1, Column D.
J - Column H divided by Column I.

Newfoundland Power Inc.
Pro Forma 2019 Cost of Service Study

UNIT COSTS BY ENERGY, DEMAND AND CUSTOMER COSTS

Line No.	Class of Service	Rate Code	Billing Statistics From Schedule 4.1 Energy Sales MWh A	Average Number of Customers B	Total Billing Demands kW - kVA C	Unit Energy Costs cent/kWh D	Unit Demand Costs By Energy Sales cent/kWh E	Unit Demand Costs By Billing Demand $/kW - $/kVA F	Unit Customer Costs By Energy Sales cent/kWh G	Unit Customer Costs By Number of Customers $/Cust/month H	Specifically Assigned / Street Lighting Cost by Sales cent/kWh I	Total Cost by Sales cent/kWh J
	DOMESTIC											
1	Domestic Regular	1.1	750,728	71,764	0	5.303	6.425	0.00	2.749	23.96	0.000	14.477
2	Domestic All Electric	1.1	2,808,986	161,854	0	5.304	6.715	0.00	1.657	23.96	0.000	13.676
3	Total Domestic	1.1	3,559,714	233,618	0	5.304	6.654	0.00	1.887	23.96	0.000	13.845
	GENERAL SERVICE											
4	(0-10 kW)	2.1	86,057	12,201	0	5.312	5.208	0.00	4.394	25.82	0.000	14.914
5	(10-100 kW)	2.1	711,568	10,560	2,750,240	5.318	5.494	14.22	0.629	35.32	0.000	11.441
6	Total (0-100 kW)	2.1	797,625	22,761	2,750,240	5.317	5.463	14.22	1.035	30.24	0.000	11.816
	(110-1000 kVA)	2.3										
7	Primary (110-350 kVA)		13,045	18	34,618	5.273	4.412	16.63	0.252	152.49	0.000	9.938
8	Secondary (110-350 kVA)		494,090	961	1,666,068	5.318	4.882	14.48	0.129	55.34	0.000	10.329
9	Transmission (350-1000 kVA)		628	2	2,932	5.163	3.269	7.00	0.992	259.43	0.000	9.424
10	Primary (350-1000 kVA)		103,392	42	276,477	5.275	4.413	16.50	0.074	152.54	0.000	9.763
11	Secondary (350-1000 kVA)		413,006	232	1,187,610	5.311	4.874	16.95	0.032	47.43	0.000	10.217
12	Total (110-1000 kVA)	2.3	1,024,161	1,255	3,167,706	5.310	4.824	15.60	0.087	58.83	0.000	10.221
	(1000 kVA and Over)	2.4										
13	Transmission		17,684	2	49,514	5.135	2.999	10.71	0.037	273.92	0.617	8.787
14	Primary		268,778	29	598,608	5.268	3.989	17.91	0.029	224.25	0.034	9.319
15	Secondary		145,517	28	389,783	5.309	4.391	16.39	0.018	77.59	0.000	9.718
16	Total (1000 kVA and Over)	2.4	431,979	59	1,037,905	5.276	4.083	17.00	0.026	156.33	0.046	9.432
17	**STREET LIGHTING**	4.1	33,104	10,830	0	5.311	6.597	0.00	5.406	13.77	32.078	49.392
18	Total		5,846,583	268,523	6,955,850	5.304	5.981		1.338	24.29	0.185	12.808

Newfoundland Power Inc.
Pro Forma 2019 Cost of Service Study

UNIT COSTS BY ENERGY, DEMAND AND CUSTOMER COSTS

NOTE:
Column
A - See Schedule 4.1, Column D.
B - See Schedule 4.1, Column C.
C - See Schedule 4.1, Column E.
D - [(Total of Energy Related Costs (Schedule 1.3, Column A) divided by Energy Sales (Schedule 1.7, Column A)) times (1 + % Classified Cost Loader (Schedule 1.6, Column G)) times 100] plus RSA Loader (Schedule 1.6, Column J).
E - Demand Related Costs (Schedule 1.3, Column B) divided by Energy Sales (Schedule 1.7, Column A) times (1 + % Classified Cost Loader (Schedule 1.6, Column G)) times 100.
F - Demand Related Costs (Schedule 1.3, Column B) divided by Total Billing Demands (Schedule 1.7, Column C) times (1 + % Classified Cost Loader (Schedule 1.6, Column G)) times 1000.
G - Customer Related Costs (Schedule 1.3, Column C) divided by Energy Sales (Schedule 1.7, Column A) times (1 + % Classified Cost Loader (Schedule 1.6, Column G)) times 100.
H - Customer Related Costs (Schedule 1.3, Column C) divided by Average Number of Customers (Schedule 1.7, Column B) times (1 + % Classified Cost Loader (Schedule 1.6, Column G)) times 1000 divided by 12.
I - Specifically Assigned Costs (Schedule 1.3 Column E) divided by Energy Sales (Schedule 1.7, Column A) times (1 + % Classified Cost Loader (Schedule 1.6, Column G)) times 100.
J - Total of Columns D, E, G and I.

FUNCTIONAL CLASSIFICATION OF AVERAGE FIXED ASSETS
(All numbers are times $1,000)

Line No.	Category	Total	Produced & Purchased Demand	Produced & Purchased Energy	Transmission Demand	Distribution: Substation Demand	Distribution: Primary Demand	Distribution: Primary Customer	Distribution: Transformers Demand	Distribution: Transformers Customer	Distribution: Secondary Demand	Distribution: Secondary Customer	Distribution: Services Customer	Distribution: Meters Customer	Distribution: St. Lighting Customer	Cust. Acc. & Cust. Serv.	Specifically Assigned	Revenue Related
		A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
1	Hydro Electric Production	211,662	96,645	115,017	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Other Generation	32,926	32,926	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Transmission	155,343	0	0	154,551	0	0	0	0	0	0	0	0	0	0	0	792	0
	Substations																	
4	Hydro Electric Production	10,702	4,887	5,816	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Other Production	1,293	1,293	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Transmission	74,980	0	0	74,699	0	0	0	0	0	0	0	0	0	0	0	281	0
7	Distribution	179,426	0	0	0	178,983	0	0	0	0	0	0	0	0	0	0	443	0
	Distribution																	
8	Land and Land Clearing	42	0	0	0	0	20	12	0	0	5	3	0	0	2	0	0	0
9	Conductors, Poles and Fittings	764,255	0	0	0	0	368,098	216,185	0	0	92,025	54,046	0	0	33,902	0	0	0
10	Transformers	160,949	0	0	0	0	0	0	115,883	45,066	0	0	0	0	0	0	0	0
11	Services	113,158	0	0	0	0	0	0	0	0	0	0	113,158	0	0	0	0	0
12	Meters	31,641	0	0	0	0	0	0	0	0	0	0	0	31,641	0	0	0	0
13	Street lighting	22,245	0	0	0	0	0	0	0	0	0	0	0	0	22,245	0	0	0
14	Total Direct Utility Plant	1,758,622	135,750	120,833	229,250	178,983	368,119	216,197	115,883	45,066	92,030	54,049	113,158	31,641	56,149	0	1,515	0
	General Utility Plant																	
15	Land and Land Clearing	4,594	277	246	662	363	747	439	235	91	187	110	230	64	114	823	4	0
16	Buildings	45,861	2,753	2,450	6,855	3,766	7,745	4,549	2,438	948	1,936	1,137	2,381	666	1,181	7,014	41	0
17	Computer Equipment	46,895	1,972	1,755	5,266	3,041	6,254	3,673	1,969	766	1,564	918	1,923	538	954	16,271	32	0
18	Misc Equipment	14,663	766	682	2,823	1,251	2,573	1,511	810	315	643	378	791	221	392	1,491	16	0
19	Transportation	30,286	498	443	4,143	3,395	6,983	4,101	2,198	855	1,746	1,025	2,147	600	1,065	1,057	28	0
20	Tele-communications	8,571	522	465	2,496	695	1,429	839	450	175	357	210	439	123	218	138	13	0
21	Total General Utility Plant	150,871	6,788	6,042	22,246	12,511	25,732	15,113	8,101	3,150	6,433	3,778	7,910	2,212	3,925	26,794	135	0
22	Total	1,909,493	142,538	126,875	251,496	191,495	393,851	231,309	123,984	48,216	98,463	57,827	121,068	33,853	60,073	26,794	1,651	0

FUNCTIONAL CLASSIFICATION OF AVERAGE FIXED ASSETS

Line No.	Category	Basis for Functional Classification
1	Hydro Electric Production	Classified based on factors shown in Schedule 5.1 Line 4.
2	Other Generation	Classified based on factors shown in Schedule 5.1 Line 5.
3	Transmission	Functional split based on Schedule 5.1 line 19. Common costs classified based on the transmission common as shown on Schedule 5.1 Line 6.
	Substations	
4	Hydro Electric Production	Functional splits based on Schedule 5.1 line 20 and classified as shown in Schedule 5.1 line 4.
5	Other Production	Functional splits on based Schedule 5.1 line 20 and classified as shown in Schedule 5.1 line 5.
6	Transmission	Functional splits based on Schedule 5.1 line 20 and common transmission costs classified as shown in Schedule 5.1 line 6.
7	Distribution	Functional splits based on Schedule 5.1 line 20 and distribution substation common costs classified as shown in Schedule 5.1 line 7.
	Distribution	
8	Land and Land Clearing	Functional splits based on Schedule 5.1 line 21 and classified as shown in Schedule 5.1 lines 8, 9 & 10.
9	Conductors, Poles and Fittings	Functional splits based on Schedule 5.1 line 22 and classified as shown in Schedule 5.1 lines 11, 12 & 13.
10	Transformers	Classified as shown in Schedule 5.1 line 14.
11	Services	Classified as shown in Schedule 5.1 line 15.
12	Meters	Classified as shown in Shedule 5.1 line 16.
13	Street lighting	Classified as shown in Schedule 5.1 line 17.
14	Total Direct Fixed Plant	Total of Lines 1 through 13.
	General Utility Plant	
15	Land and Land Clearing	Functionalized based on general property land and land rights (See Schedule 5.1 line 23). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
16	Buildings	Functionalized based on general property buildings and structures (See Schedule 5.1 line 24). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
17	Computer Equipment	Functionalized based on Computer Hardware and Software (See Schedule 5.1 line 25). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
18	Miscellaneous Equipment	Functionalized based on General Property Other Equipment (See Schedule 5.1 line 26). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
19	Transportation	Functionalized based on Transportation (See Schedule 5.1 line 27). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
20	Tele-communications	Functionalized based on Total Communications (See Schedule 5.1 line 28). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
21	Total General Property	Total of Lines 15 through 20.
22	Total	Total of Lines 14 and 21.

FUNCTIONAL CLASSIFICATION OF AVERAGE ACCUMULATED DEPRECIATION
(All numbers are times $1,000)

Line No.	Category	Total A	Produced & Purchased Demand B	Produced & Purchased Energy C	Transmission Demand D	Distribution: Substation Demand E	Distribution: Primary Demand F	Distribution: Primary Customer G	Distribution: Transformers Demand H	Distribution: Transformers Customer' I	Distribution: Secondary Demand J	Distribution: Secondary Customer K	Distribution: Services Customer L	Distribution: Meters Customer M	Distribution: St. Lighting Customer N	Cust. Acc. & Cust. Serv. O	Specifically Assigned P
1	Hydro Electric Production	76,552	34,954	41,598	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Other Generation	19,902	19,902	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Transmission	71,039	0	0	70,677	0	0	0	0	0	0	0	0	0	0	0	362
	Substations																
4	Hydro Electric Production	2,729	1,246	1,483	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Other Production	330	330	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Transmission	19,116	0	0	19,045	0	0	0	0	0	0	0	0	0	0	0	72
7	Distribution	45,745	0	0	0	45,632	0	0	0	0	0	0	0	0	0	0	113
	Distribution																
8	Land and Land Clearing	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	Conductors, Poles and Fittings	334,106	0	0	0	0	160,332	94,163	0	0	40,083	23,541	0	0	15,986	0	0
10	Transformers	47,208	0	0	0	0	0	0	33,990	13,218	0	0	0	0	0	0	0
11	Services	78,302	0	0	0	0	0	0	0	0	0	0	78,302	0	0	0	0
12	Meters	12	0	0	0	0	0	0	0	0	0	0	0	12	0	0	0
13	Street lighting	10,460	0	0	0	0	0	0	0	0	0	0	0	0	10,460	0	0
	General Plant																
14	Land and Land Rights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15	Buildings	15,951	958	852	2,384	1,310	2,694	1,582	848	330	673	396	828	232	411	2,439	14
16	Computer Equipment	22,427	943	839	2,518	1,454	2,991	1,757	942	366	748	439	919	257	456	7,782	15
17	Misc. Equipment	8,662	453	403	1,668	739	1,520	893	478	186	380	223	467	131	232	881	10
18	Transportation	13,413	221	196	1,835	1,504	3,093	1,816	974	379	773	454	951	266	472	468	12
19	Tele-communications	5,631	343	305	1,640	457	939	552	296	115	235	138	289	81	143	91	9
20	Total	771,588	59,348	45,678	99,767	51,096	171,569	100,763	37,527	14,594	42,892	25,191	81,756	978	28,160	11,661	607

FUNCTIONAL CLASSIFICATION OF AVERAGE ACCUMULATED DEPRECIATION

Line No.	Category	Basis for Functional Classification
1	Hydro Electric Production	Classified based on factors shown in Schedule 5.1 Line 4.
2	Other Generation	Classified based on factors shown in Schedule 5.1 Line 5.
3	Transmission	Functional split based on Schedule 5.1 line 19. Common costs classified based on the transmission common as shown on Schedule 5.1 Line 6.
	Substations	
4	Hydro Electric Production	Functional splits based on Schedule 5.1 line 20 and classified as shown in Schedule 5.1 line 4.
5	Other Production	Functional splits on based Schedule 5.1 line 20 and classified as shown in Schedule 5.1 line 5.
6	Transmission	Functional splits based on Schedule 5.1 line 20 and common transmission costs classified as shown in Schedule 5.1 line 6.
7	Distribution	Functional splits based on Schedule 5.1 line 20 and distribution substation common costs classified as shown in Schedule 5.1 line 7.
	Distribution	
8	Land and Land Rights	Functional splits based on Schedule 5.1 line 21 and classified as shown in Schedule 5.1 lines 8, 9 & 10.
9	Conductors, Poles and Fittings	Functional splits based on Schedule 5.1 line 22 and classified as shown in Schedule 5.1 lines 11, 12 & 13.
10	Transformers	Classified as shown in Schedule 5.1 line 14.
11	Services	Classified as shown in Schedule 5.1 line 15.
12	Meters	Classified as shown in Schedule 5.1 line 16.
13	Street lighting	Classified as shown in Schedule 5.1 line 17.
	General Plant	
14	Land and Land Clearing	Functionalized based on general property land and land rights (See Schedule 5.1 line 23). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
15	Buildings	Functionalized based on general property buildings and structures (See Schedule 5.1 line 24). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
16	Computer Equipment	Functionalized based on Computer Hardware and Software (See Schedule 5.1 line 25). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
17	Miscellaneous Equipment	Functionalized based on General Property Other Equipment (See Schedule 5.1 line 26). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
18	Transportation	Functionalized based on Transportation (See Schedule 5.1 line 27). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
19	Tele-communications	Functionalized based on Total Communications (See Schedule 5.1 line 28). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
20	Total	Total of Lines 1 through 19.

FUNCTIONAL CLASSIFICATION OF AVERAGE NET CONTRIBUTIONS IN AID OF CONSTRUCTION (CIAC)
(All numbers are times $1,000)

Line No.	Category	Total A	Produced & Purchased Demand B	Produced & Purchased Energy C	Transmission Demand D	Distribution Substation Demand E	Distribution Primary Demand F	Distribution Primary Customer G	Distribution Transformers Demand H	Distribution Transformers Customer I	Distribution Secondary Demand J	Distribution Secondary Customer K	Distribution Services Customer L	Distribution Meters Customer M	Distribution St. Lighting Customer N	Cust. Acc. & Cust. Serv. O	Specifically Assigned P
1	Hydro Electric Production	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Other Generation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Transmission	554	0	0	551	0	0	0	0	0	0	0	0	0	0	0	3
	Substations																
4	Hydro Electric Production	121	55	66	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Other Production	15	15	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Transmission	845	0	0	842	0	0	0	0	0	0	0	0	0	0	0	3
7	Distribution	2,023	0	0	0	2,018	0	0	0	0	0	0	0	0	0	0	5
	Distribution																
8	Land and Land Clearing	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	Conductors, Poles and Fittings	32,930	0	0	0	0	15,861	9,315	0	0	3,965	2,329	0	0	1,461	0	0
10	Transformers	2,319	0	0	0	0	0	0	1,669	649	0	0	0	0	0	0	0
11	Services	1,249	0	0	0	0	0	0	0	0	0	0	1,249	0	0	0	0
12	Meters	955	0	0	0	0	0	0	0	0	0	0	0	955	0	0	0
13	Street lighting	585	0	0	0	0	0	0	0	0	0	0	0	0	585	0	0
	General Plant																
14	Land and Land Rights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15	Buildings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
16	Computer Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17	Misc. Equipment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18	Transportation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
19	Tele-communications	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20	Total	41,596	70	66	1,393	2,018	15,861	9,315	1,669	649	3,965	2,329	1,249	955	2,046	0	11

FUNCTIONAL CLASSIFICATION OF AVERAGE NET CONTRIBUTIONS IN AID OF CONSTRUCTION (CIAC)

Line No.	Category	Basis for Functional Classification
1	Hydro Electric Production	Classified based on factors shown in Schedule 5.1 Line 4.
2	Other Generation	Classified based on factors shown in Schedule 5.1 Line 5.
3	Transmission	Functional split based on Schedule 5.1 line 19. Common costs classified based on the transmission common as shown on Schedule 5.1 Line 6.
	Substations	
4	Hydro Electric Production	Functional splits based on Schedule 5.1 line 20 and classified as shown in Schedule 5.1 line 4.
5	Other Production	Functional splits on based Schedule 5.1 line 20 and classified as shown in Schedule 5.1 line 5.
6	Transmission	Functional splits based on Schedule 5.1 line 20 and common transmission costs classified as shown in Schedule 5.1 line 6.
7	Distribution	Functional splits based on Schedule 5.1 line 20 and distribution substation common costs classified as shown in Schedule 5.1 line 7.
	Distribution	
8	Land and Land Clearing	Functional splits based on Schedule 5.1 line 21 and classified as shown in Schedule 5.1 lines 8, 9 & 10.
9	Conductors, Poles and Fittings	Functional splits based on Schedule 5.1 line 22 and classified as shown in Schedule 5.1 lines 11, 12 & 13.
10	Transformers	Classified as shown in Schedule 5.1 line 14.
11	Services	Classified as shown in Schedule 5.1 line 15.
12	Meters	Classified as shown in Schedule 5.1 line 16.
13	Street lighting	Classified as shown in Schedule 5.1 line 17.
	General Plant	
14	Land and Land Clearing	Functionalized based on general property land and land rights (See Schedule 5.1 line 23. Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
15	Buildings	Functionalized based on general property buildings and structures (See Schedule 5.1 line 24). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
16	Computer Equipment	Functionalized based on Computer Hardware and Software (See Schedule 5.1 line 25). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
17	Miscellaneous Equipment	Functionalized based on General Property Other Equipment (See Schedule 5.1 line 26). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
18	Transportation	Functionalized based on Transportation (See Schedule 5.1 line 27). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
19	Tele-communications	Functionalized based on Total Communications (See Schedule 5.1 line 28). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
20	Total	Total of Lines 1 through 19.

Newfoundland Power Inc.

Pro Forma 2019 Cost of Service Study

FUNCTIONAL CLASSIFICATION OF AVERAGE RATE BASE

(All numbers are times $1,000)

Line No.	Category	Total	Produced & Purchased Demand	Produced & Purchased Energy	Transmission Demand	Distribution: Substation Demand	Distribution: Primary Demand	Distribution: Primary Customer	Distribution: Transformers Demand	Distribution: Transformers Customer	Distribution: Secondary Demand	Distribution: Secondary Customer	Distribution: Services Customer	Distribution: Meters Customer	Distribution: St. Lighting Customer	Cust. Acc. & Cust. Serv.	Specifically Assigned	Revenue Related
		A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	
1	Hydro Electric Production	135,110	61,691	73,419	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Other Generation	13,023	13,023	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Transmission	84,304	0	0	83,874	0	0	0	0	0	0	0	0	0	0	0	430	0
	Substations																	
4	Hydro Electric Production	7,974	3,641	4,333	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Other Production	963	963	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Transmission	55,863	0	0	55,654	0	0	0	0	0	0	0	0	0	0	0	209	0
7	Distribution	133,681	0	0	0	133,351	0	0	0	0	0	0	0	0	0	0	330	0
	Distribution																	
8	Land and Land Clearing	42	0	0	0	0	20	12	0	0	5	3	0	0	2	0	0	0
9	Conductors, Poles and Fittings	430,150	0	0	0	0	207,766	122,021	0	0	51,941	30,505	0	0	17,915	0	0	0
10	Transformers	113,741	0	0	0	0	0	0	81,893	31,847	0	0	0	0	0	0	0	0
11	Services	34,856	0	0	0	0	0	0	0	0	0	0	34,856	0	0	0	0	0
12	Meters	31,629	0	0	0	0	0	0	0	0	0	0	0	31,629	0	0	0	0
13	Street lighting	11,785	0	0	0	0	0	0	0	0	0	0	0	0	11,785	0	0	0
14	Total Direct Net Utility Plant	1,053,121	79,318	77,752	139,529	133,351	207,786	122,033	81,893	31,847	51,947	30,508	34,856	31,629	29,702	0	969	0
	General Plant																	
15	Land and Land Rights	4,594	277	246	662	363	747	439	235	91	187	110	230	64	114	823	4	0
16	Buildings	29,910	1,795	1,598	4,471	2,456	5,051	2,967	1,590	618	1,263	742	1,553	434	770	4,574	27	0
17	Computer Equipment	24,468	1,029	916	2,748	1,587	3,263	1,916	1,027	399	816	479	1,003	280	498	8,490	17	0
18	Misc. Equipment	6,001	314	279	1,155	512	1,053	618	331	129	263	155	324	91	161	610	7	0
19	Transportation	16,873	277	247	2,308	1,892	3,891	2,285	1,225	476	973	571	1,196	334	593	589	15	0
20	Tele-communications	2,939	179	159	856	238	490	288	154	60	123	72	151	42	75	47	5	0
21	Total General Plant	84,785	3,871	3,446	12,201	7,048	14,496	8,513	4,563	1,775	3,624	2,128	4,456	1,246	2,211	15,133	75	0
22	Total Net Utility Plant	1,137,906	83,190	81,198	151,729	140,399	222,282	130,546	86,456	33,622	55,570	32,637	39,312	32,875	31,913	15,133	1,043	0
	Deductions from Rate Base																	
23	Contributions in Aid of Construction	41,596	70	66	1,393	2,018	15,861	9,315	1,669	649	3,965	2,329	1,249	955	2,046	0	11	0
24	Security Deposits	1,246	95	84	127	112	195	115	53	20	49	29	107	16	66	178	1	0
25	Post Retirement Benefits Liability	64,512	4,907	4,364	6,564	5,781	10,118	5,943	2,727	1,060	2,530	1,486	5,559	826	3,398	9,206	42	0
26	Future Income Taxes - Depreciation/CCA	26,078	1,906	1,861	3,477	3,218	5,094	2,992	1,981	771	1,274	748	901	753	731	347	24	0
27	Future Income Taxes - Pension/OPEBS	(18,591)	(1,414)	(1,257)	(1,892)	(1,666)	(2,916)	(1,713)	(786)	(306)	(729)	(428)	(1,602)	(238)	(979)	(2,653)	(12)	0
28	Demand Management Incentive Liability	(941)	(941)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
29	Total Deductions	113,900	4,623	5,117	9,670	9,462	28,353	16,652	5,644	2,195	7,088	4,163	6,215	2,313	5,262	7,077	66	0
	Additions to Rate Base																	
30	Average Deferred Charges	90,843	6,910	6,145	9,244	8,141	14,248	8,368	3,840	1,493	3,562	2,092	7,829	1,163	4,785	12,963	60	0
31	Unamortized Cost Recovery Deferrals	16,264	1,237	1,100	1,655	1,458	2,551	1,498	687	267	638	375	1,402	208	857	2,321	11	0
32	Customer Financing Programs	2,477	188	168	252	222	389	228	105	41	97	57	213	32	130	353	2	0
33	Weather Normalization (hydro equal.)	2,867	0	2,867	0	0	0	0	0	0	0	0	0	0	0	0	0	0
34	Weather Normalization (Degree Day Norm.)	719	73	71	133	123	194	0	76	0	49	0	0	0	0	0	1	0
35	Cash Working Capital Allowance	9,907	694	1,810	810	716	1,244	730	346	134	311	182	649	108	400	1,054	5	714
36	Materials And Supplies	6,475	299	266	1,598	606	1,246	732	392	153	311	183	383	107	190	0	9	0
37	Total Additions	129,551	9,401	12,426	13,692	11,266	19,872	11,556	5,446	2,088	4,968	2,889	10,476	1,618	6,362	16,691	87	714
38	Total Average Rate Base	1,153,557	87,967	88,507	155,751	142,202	213,801	125,451	86,258	33,515	53,450	31,363	43,572	32,181	33,013	24,747	1,065	714

Newfoundland Power Inc.
Pro Forma 2019 Cost of Service Study

FUNCTIONAL CLASSIFICATION OF AVERAGE RATE BASE

Line No.	Category	Basis for Functional Classification
1	Hydro Electric Production	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2)
2	Other Generation	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2)
3	Transmission	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2)
	Substations	
4	Hydro Electric Production	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
5	Other Production	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
6	Transmission	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
7	Distribution	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
	Distribution	
8	Land and Land Clearing	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
9	Conductors, Poles and Fittings	
10	Transformers	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
11	Services	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
12	Meters	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
13	Street lighting	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
14	Total Direct Net Utility Plant	Total of Line 1 to 13.
	General Plant	
15	Land and Land Rights	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
16	Buildings	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
17	Computer Equipment	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
18	Misc. Equipment	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
19	Transportation	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
20	Tele-communications	Difference Between the Allocated Average Fixed assets (Schedule 2.1) and the Average Accumulated Depreciation (Schedule 2.2).
21	Total General Plant	Total of Lines 15 to 20.
22	Total Net Utility Plant	Total of Line 14 and Line 21.
	Deductions from Rate Base	
23	Contributions in Aid of Construction	Taken from totals shown on Schedule 2.3.
24	Security Deposits	Functional Classification based on the Weighted Split for Administration and General. (See Schedule 3.2, Line 27).
25	Post Retirement Benefits Liability	Functional Classification based on the Weighted Split for Administration and General. (See Schedule 3.2, Line 27).
26	Future Income Taxes - Depreciation/CCA	Functional Classification based on Total Net Utility Plant (Line 22).
27	Future Income Taxes - Pension/OPEBS	Functional Classification based on the Weighted Split for Administration and General. (See Schedule 3.2, Line 27).
28	DMI Liability	Functional Classification Classified 100% to Produced and Purchased Demand.
29	Total Deductions	Total of Lines 23 through 28.
	Additions to Rate Base	
30	Average Deferred Charges	Functional Classification based on the Weighted Split for Administration and General. (See Schedule 3.2, Line 27).
31	Unamortized Cost Recovery Deferrals	Functional Classification based on the Weighted Split for Administration and General. (See Schedule 3.2, Line 27).
32	Customer Financing Programs	Functional Classification based on the Weighted Split for Administration and General. (See Schedule 3.2, Line 27).
33	Weather Normalization (hydro equal.)	Classified 100% to Energy.
34	Weather Normalization (Degree Day Norm.)	Functional Classification split based on Total Net Utility Plant (Line 22) excluding Customer Classification Functions
35	Cash Working Capital Allowance	Functional Classification based on Adminsitration and General Expenses (See Schedule 3.2, Line 32) and CDM Actvities (See Schedule 3.2, Line 36)
36	Materials And Supplies	Functionalized based on Year End Inventory (See Schedule 5.1 Line 31). Classification based on total direct utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned (Schedule 2.1).
37	Total Additions	Total of Lines 30 through 36.
38	Total Rate Base	Line 22 less Line 29 plus Line 37.

LIST OF OPERATING EXPENSES NET OF GENERAL EXPENSES TRANSFERRED TO CAPITAL (GEC)
(All numbers are times $1,000)

Expense Category Code	Description	Including Non-Regulated Expenses Total	Labour	Non-Labour	Non-Regulated Expenses	Excluding Non-Regulated Expenses Total Excl.	Labour Excl.	Non-Labour Excl.
	PURCHASED POWER WEATHER ADJUSTED							
PPH	Nfld. Hydro - Firm	504,774	0	504,774	0	504,774	0	504,774
	TOTAL PURCHASED POWER	504,774	0	504,774	0	504,774	0	504,774
	PRODUCTION							
Hydro	Hydro - Direct Operating and Maintenance	7	7	0	0	7	7	0
Hydro	Hydro - Supervision and misc.	3,403	1,620	1,782	0	3,403	1,620	1,782
Oth Prod	Other Production - Direct Operating and Maintenance	414	291	123	0	414	291	123
Oth Prod	Other Production - Fuel and Lubricants	118	0	118	0	118	0	118
	TOTAL PRODUCTION	3,942	1,919	2,023	0	3,942	1,919	2,023
Gen Sys Opr	SYSTEM OPERATIONS	1,495	1,450	45	0	1,495	1,450	45
Gen PTD	TOOLS, SAFETY, EQUIPMENT REPAIR & RUBBER GLOVE TESTING	1,393	478	914	0	1,393	478	914
Gen PTD	GENERAL OPERATIONS	3,742	3,230	512	0	3,742	3,230	512
	TOTAL MISC TECHNICAL OPERATING COSTS	6,630	5,158	1,471	0	6,630	5,158	1,471
Gen PTD	ENVIRONMENTAL COST	287	203	84	0	287	203	84
	SUBSTATIONS							
Subs	Direct O&M	2,361	1,717	645	0	2,361	1,717	645
	TRANSMISSION							
Transm	Direct O&M	712	234	478	0	712	234	478
	DISTRIBUTION							
CPF	Direct O&M - Lines/poles/fittings	3,369	3,088	281	0	3,369	3,088	281
Services	Direct O&M - Services	2,685	2,586	99	0	2,685	2,586	99
Strlgts	Direct O&M - Street Lights	1,897	1,611	286	0	1,897	1,611	286
Transf.	Direct O&M - Transformers	180	174	6	0	180	174	6
Meters	Direct O&M - Meters	108	91	16	0	108	91	16
Gen D	Direct O&M - Vegetation Management	1,545	119	1,426	0	1,545	119	1,426
Gen D	Distribution Line Inspections	239	228	11	0	239	228	11
Gen D	Pre Issues	214	0	214	0	214	0	214
	TOTAL DISTRIBUTION	10,235	7,897	2,338	0	10,235	7,897	2,338
	COMMUNICATIONS							
Gen Comm	Direct O&M - General	1,283	2	1,281	0	1,283	2	1,281
	TOTAL COMMUNICATIONS	1,283	2	1,281	0	1,283	2	1,281
	CUSTOMER SERVICE							
Cust Acc	Customer Service Administration, Billing & Meter Reading	2,045	1,712	332	36	2,009	1,682	327
Cust Acc	Credit, Collections & Cash Control	2,331	877	1,454		2,331	877	1,454

LIST OF OPERATING EXPENSES NET OF GENERAL EXPENSES TRANSFERRED TO CAPITAL (GEC)
(All numbers are times $1,000)

Expense Category Code	Description	Including Non-Regulated Expenses Total	Including Non-Regulated Expenses Labour	Including Non-Regulated Expenses Non-Labour	Non-Regulated Expenses	Excluding Non-Regulated Expenses Total Excl.	Excluding Non-Regulated Expenses Labour Excl.	Excluding Non-Regulated Expenses Non-Labour Excl.
Cust Acc	Inquiry	3,330	3,296	34		3,330	3,296	34
Cust Acc	Uncollectable Bills	1,980	0	1,980	0	1,980	0	1,980
CDM - GA	Conservation and Demand Management - General Activities	733	371	362		733	371	362
CDM - Prom	Conservation and Demand Management - Program Costs	11,461	2,061	9,400		11,461	2,061	9,400
CDM - DM	Curtailable Service Option	375	7	368		375	7	368
CDM - Prom	Conservation and Demand Management - Program Costs Deferred	(6,864)	(1,153)	(5,711)		(6,864)	(1,153)	(5,711)
			0	0				
	TOTAL CUSTOMER SERVICE	15,391	7,172	8,220	36	15,356	7,142	8,214
	FINANCE							
A&G	Finance	1,548	1,287	261		1,548	1,287	261
Labour Rela	Company Pension Scheme	442	0	442		442	0	442
Labour Rela	Other Post Retirement Benefits	5,203	0	5,203		5,203	0	5,203
	TOTAL FINANCE	7,193	1,287	5,906	0	7,193	1,287	5,906
A&G	CORPORATE COMMUNICATIONS	931	405	526	42	889	387	502
			0	0				
	MANAGEMENT INFORMATION SYSTEMS		0	0				
A&G	Computer Operations	875	826	48	0	875	826	48
A&G	Systems Development and Support	4,526	1,857	2,669	0	4,526	1,857	2,669
	TOTAL MIS	5,401	2,683	2,718	0	5,401	2,683	2,718
	HUMAN RESOURCE AND EMPLOYEE RELATED COSTS							
A&G	Human Resources Division	2,116	1,642	474	0	2,116	1,642	474
A&G	Employee Welfare & Coffee & Lunchroom Supplies	305	13	292	0	305	13	292
	TOTAL HUMAN RESOURCE AND EMPLOYEE RELATED COSTS	2,421	1,655	766	0	2,421	1,655	766
	ADMINSTRATION & MISCELLANEOUS							
A&G	Administration, Support Staff and Internal Audit	7,907	4,553	3,354	3,256	4,651	2,678	1,973
A&G	Misc. Costs - General	3,614	1,010	2,604	242	3,372	943	2,430
Ins & Dam.	Misc. Costs - Property Insurace & Public Liability (Not Insured)	1,673	1	1,672	0	1,673	1	1,672
A&G	RST Assessment	294	0	294	0	294	0	294
Revenue Related	PUB Assessments	958	0	958	0	958	0	958
			0	0				
A&G	Property Maintenance	2,061	269	1,792	0	2,061	269	1,792
A&G	Printing Services	253	183	70	0	253	183	70
	TOTAL ADMINISTRATION & MISCELLANEOUS	16,760	6,016	10,744	3,498	13,262	4,074	9,188
Vehicles	VEHICLE MAINTENANCE	1,673	0	1,673	0	1,673	0	1,673
	TOTAL OPERATING AND MAINTENANCE EXPENSES Net of GEC & (Excluding RSA & MTA Expense)	579,996	36,348	543,647	3,576	576,419	34,357	542,062

Expense Category Code	Cost of Service Expense Category
A&G	Administration and General (Excluding Labour Related Costs).
CDM - GA	Conservation and Demand Management - General Activities
CDM - Prom	Conservation and Demand Management - Program Costs
CDM - DM	Curtailable Service Option and Voltage Management
Curtail	Curtailable Credits Paid Customers.
CPF	Operating expenses directly associated with Conductors, Poles and Fittings.
Cust Acc	Operating Expenses associated with Customer Accounting and Customer Service.
Gen Comm	Communication Expenses Related to the VHS/Mobile radio system.
Gen D	General expenses to be split over the categories within distribution.
Gen PTD	General expenses to be split over Production, Transmission and Distribution.
Gen Sys Opr	General expenses associated with the Systems Control Centre.
Gen TD	General expenses to be split over Transmission and Distribution.
Hydro	Operating expenses associated with Hydraulic Generation.
Labour Rela	Administration and general Expenses directly related to Labour.
Meters	Operating expenses directly associated with Meters.
Oth Prod	Operating expenses associated with Diesel and Gas Turbine Generation.
Ins & Dam.	Property Insurance, Public Liability, Risk Management.
PPDL	Purchase Power Costs for Secondary Energy from Deer Lake Power Firmed up by Hydro.
PPH	Purchase Power Costs from Hydro for Firm Energy.
Revenue Related	Operating expenses related to revenue.
Services	Operating expenses directly associated with Services.
Strlgts	Operating expenses directly associated with Street Lighting.
Subs	Operating expenses directly associated with Substations.
Transf.	Operating expenses directly associated with Transformers.
Transm	Operating expenses directly associated with Transmission.
Vehicles	Operating expenses directly associated with Vehicles.

Newfoundland Power Inc.
Pro Forma 2019 Cost of Service Study

FUNCTIONAL CLASSIFICATION OF OPERATING AND MAINTENANCE EXPENSES
(All numbers are times $1000)

Line No.	Catagory	Total A	Produced & Purchased Demand B	Produced & Purchased Energy C	Transmission Demand D	Distribution: Substation Demand E	Distribution: Primary Demand F	Distribution: Primary Customer G	Distribution: Transformers Demand H	Distribution: Transformers Customer I	Distribution: Secondary Demand J	Distribution: Secondary Customer K	Distribution: Services Customer L	Distribution: Meters Customer M	Distribution: St. Lighting Customer N	Customer Acc. & Cust. Serv. O	Specifically Assigned P	Revenue Related Q
	Purchase Power Expense																	
1	Purchases from Hydro - Production related	391,276	134,008	257,267	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Purchases from Hydro - Transmission related	54,422	54,422	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Demand Mangement Incentive Account	(2,687)	(2,687)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	Sub Total	443,011	185,743	257,267	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Direct Operating & Maintenance Expense																	
5	Hydraulic Production	3,410	1,557	1,853	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Other Production	532	532	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	Transmission	712	0	0	708	0	0	0	0	0	0	0	0	0	0	0	4	0
	Substations																	
8	Hydarulic Plants	95	43	52	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	Other Production	11	11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	Transmission	665	0	0	662	0	0	0	0	0	0	0	0	0	0	0	2	0
11	Distribution	1,590	0	0	0	1,586	0	0	0	0	0	0	0	0	0	0	4	0
	Distribution																	
12	Lines/poles/fittings	3,369	0	0	0	0	1,698	997	0	0	424	249	0	0	0	0	0	0
13	Services	2,685	0	0	0	0	0	0	0	0	0	0	2,685	0	0	0	0	0
14	Street Lights	1,897	0	0	0	0	0	0	0	0	0	0	0	0	1,897	0	0	0
15	Transformers	180	0	0	0	0	0	0	130	50	0	0	0	0	0	0	0	0
16	Meters	108	0	0	0	0	0	0	0	0	0	0	0	108	0	0	0	0
17	Customer Accounting	9,650	0	0	0	0	0	0	0	0	0	0	0	0	0	9,650	0	0
18	Subtotal Direct O&M	24,903	2,144	1,904	1,371	1,586	1,698	997	130	50	424	249	2,685	108	1,897	9,650	10	0
	General System Expenses																	
19	Related to Distribution	1,997	0	0	0	296	494	290	126	49	124	73	310	40	195	0	1	0
20	Related to Prod, Trans. & Distribution	5,422	547	486	633	556	929	546	237	92	232	136	583	75	367	0	4	0
21	Related to Vehicles	1,673	28	24	229	188	386	227	121	47	96	57	119	33	59	58	2	0
22	System Control Centre Expenses	1,495	91	81	240	160	268	157	68	27	67	39	168	22	106	0	0	0
23	General Communication Expenses	1,283	39	35	186	123	205	120	52	20	51	30	129	16	81	196	0	0
24	Subtotal General System Expenses	11,871	704	626	1,287	1,323	2,282	1,340	605	235	570	335	1,309	185	808	254	7	0
	Administration and General																	
25	Insurance, Injuries & Damages	1,673	122	119	223	206	327	192	127	49	82	48	58	48	47	22	2	0
26	Labour Related	5,645	429	382	574	506	885	520	239	93	221	130	486	72	297	806	4	0
27	Other Administration And General Expenses	20,890	1,589	1,413	2,126	1,872	3,277	1,924	883	343	819	481	1,800	268	1,100	2,981	14	0
28	Amortization - 2019 General Cost Deferral	1,752	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,752
29	Pension and OPEBs Variance Deferral	(896)	(68)	(61)	(91)	(80)	(141)	(83)	(38)	(15)	(35)	(21)	(77)	(11)	(47)	(128)	(1)	0
30	2019 Revenue Req Shortfall	(145)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	(145)
31	PUB Assessments	958	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	958
32	Subtotal Administration and General Expenses	29,877	2,072	1,854	2,832	2,504	4,348	2,554	1,211	471	1,087	638	2,267	377	1,397	3,681	18	2,565
	CDM Activities																	
33	CDM - General Activities	733	56	50	75	66	115	68	31	12	29	17	63	9	39	105	0	0
34	CDM - Program Costs	4,597	0	4,597	0	0	0	0	0	0	0	0	0	0	0	0	0	0
35	Curtailable Service Option	375	365	0	3	3	3	0	0	0	1	0	0	0	0	0	0	0
36	Subtotal CDM Activities	5,705	421	4,647	77	69	118	68	31	12	30	17	63	9	39	105	0	0
37	Total O&M (less RSA, MTA and Rural Deficit)	515,367	191,085	266,298	5,567	5,483	8,446	4,959	1,977	769	2,112	1,240	6,324	679	4,141	13,690	35	2,565

Newfoundland Power Inc.

Pro Forma 2019 Cost of Service Study

FUNCTIONAL CLASSIFICATION OF OPERATING AND MAINTENANCE EXPENSES

Line No.	Category	Basis for Functional Classification
	Column A - Total	From Schedule 3.1 less rural deficit plus regulatory deferrals (Lines 28, 29 & 30)
	Purchase Power Expense	Excludes the rural deficit of $61,762,933
1	Purchases from Hydro - Production related	Based on functional classification splits shown in Schedule 5.1, Line 1. (Split between Hydro-Production and Hydro-Transmission based on split shown in Schedule 5.1, Line 18.
2	Purchases from Hydro - Transmission related	Based on functional classification splits shown in Schedule 5.1, Line 2. (Split between Hydro-Production and Hydro-Transmission based on split shown in Schedule 5.1, Line 18.
3	Demand Mangement Incentive Account	Classification based on 100% Purchase Power Demand
4	Sub Total	Total of Lines 1 - 3.
	Direct Operating & Maintenance Costs	
5	Hydraulic Production	Based on classification splits shown in Schedule 5.1, Line 4.
6	Other Production	Based on classification splits shown in Schedule 5.1, Line 5.
7	Transmission	Functional split based on Schedule 5.1 line 19. Classified based on the transmission general as shown on Schedule 5.1 Line 6.
	Substations	
8	Hydarulic Plants	Functional splits based on schedule 5.1 line 20 and classified as shown in schedule 5.1 line 4.
9	Other Production	Functional splits based on schedule 5.1 line 20 and classified as shown in schedule 5.1 line 5.
10	Transmission	Functional splits based on schedule 5.1 line 20 and classified as shown in schedule 5.1 line 6.
11	Distribution	Functional splits based on schedule 5.1 line 20 and classified as shown in schedule 5.1 line 7.
	Distribution	
12	Lines/poles/fittings	Functional splits based on schedule 5.1 line 22 (excluding street lighting) and classified as shown in schedule 5.1 lines 11 & 12.
13	Services	Classified as shown in schedule 5.1 line 15.
14	Street Lights	Classified as shown in schedule 5.1 line 17.
15	Transformers	Classified as shown in schedule 5.1 line 14..
16	Meters	Classified as shown in schedule 5.1 line 16.
17	Customer Accounting	Classified 100% to Customer Accounting (Customer).
18	Subtotal Direct O&M	Total of Lines, 5 to 17.
	General System Expenses	Functional Classification based on a weighted average total of the splits for fixed assets (Schedule 2.1, Line 22) and O&M (Schedule 3.2 Line 18). The weighting used is: 50.4% operating, and 49.6% capital.

		Produced & Purchased	Produced & Purchased	Transmission	Distribution										Cust. Acc. &	Specifically	Revenue
					Substation	Primary		Transformers		Secondary		Services	Meters	St. Lighting			
	Total	Demand	Energy	Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Cust. Serv.	Assigned	Related
	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
Weighted Splits	100.0%	8.0%	7.1%	9.3%	8.2%	13.7%	8.0%	3.5%	1.4%	3.4%	2.0%	8.6%	1.1%	5.4%	20.2%	0.1%	0.0%

Line No.	Category	Basis for Functional Classification
19	Related to Distribution	Functional Classification based on the weighted split shown for Columns E through N & the distribution portion of Column P.
20	Related to Prod, Trans. & Distribution	Functional Classification based on the weighted split shown for Columns B through N & P.
21	Related to Vehicles	Functional Classification based on splits for vehicle fixed assets (see schedule 2.4 line 19).
22	System Control Centre Expenses	Functionalized based on a study of SCADA plant (see Schedule 5.1, Line 29). Classification based on functional categories shown for general system expenses in columns B through N.
23	General Communications Expenses	Functionalized based on a study of Communications Expenses (see Schedule 5.1, Line 30). Classification based on functional categories shown for general system expenses in columns B through O.
24	Subtotal General System Expenses	Total of all Lines 19 to 23.
	Administration and General Expenses	Functional Classification based on a weighted average total of the splits for fixed assets (Schedule 2.1, Line 22) and O&M (Schedule 3.2 Lines 20 plus 26). The weighting used is: 50.4% operating, and 49.6% capital.

Split for Administration and General		Produced & Purchased	Produced & Purchased	Transmission	Distribution										Cust. Acc. &	Specifically	Revenue
					Substation	Primary		Transformers		Secondary		Services	Meters	St. Lighting			
	Total	Demand	Energy	Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Cust. Serv.	Assigned	Related
	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
Weighted Splits	100.0%	7.6%	6.8%	10.2%	9.0%	15.7%	9.2%	4.2%	1.6%	3.9%	2.3%	8.6%	1.3%	5.3%	14.3%	0.1%	0.0%

Line No.	Category	Basis for Functional Classification
25	Insurance, Injuries & Damages	Functional Classification based on Net Utility Plant in Service (See Schedule 2.4, Line 22)
26	Labour Related	Functional Classification based on the Weighted Split for Administration and General.
27	Other Administration And General Expenses	Functional Classification based on the Weighted Split for Administration and General.
28	Amortization - 2019 General Cost Deferral	Assigned 100% as Revenue Related.
29	Pension and OPEBs Variance Deferral	Functional Classification based on the Weighted Split for Administration and General.
30	2019 Revenue Requirment Shortfall	Assigned 100% as Revenue Related.
31	PUB Assessments	Assigned 100% as Revenue Related.
32	Subtotal Administration and General	Total for Lines 25 to 31.
33	CDM - General Activities	Functional Classification based on the Weighted Split for Administration and General.
34	CDM - Program Costs	Functional Classification based 100% avoided energy supply cost
35	Curtaible Service Option	Functional Classification based on direct O&M classified to demand including purchase power.
36	Subtotal CDM Activities	Total for Lines 33 to 35
37	Total O&M	Totals of Lines 4, 18, 24, 32 and 36.

Newfoundland Power Inc.

Pro Forma 2019 Cost of Service Study

FUNCTIONAL CLASSIFACTION OF DEPRECIATION EXPENSES (NET OF AMORTIZED CIAC)

(All numbers are times $1,000)

Line No.	Category	Total A	Produced & Purchased Demand B	Produced & Purchased Energy C	Transmission Demand D	Distribution: Substation Demand E	Distribution: Primary Demand F	Distribution: Primary Customer G	Distribution: Transformers Demand H	Distribution: Transformers Customer I	Distribution: Secondary Demand J	Distribution: Secondary Customer K	Distribution: Services Customer L	Distribution: Meters Customer M	Distribution: St. Lighting Customer N	Cust. Acc. & Cust. Serv. O	Specifically Assigned P
1	Hydro Electric Production	5,209	2,379	2,831	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Other Generation	1,587	1,587	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	Transmission	4,650	0	0	4,626	0	0	0	0	0	0	0	0	0	0	0	24
	Substations																
4	Hydro Electric Production	312	142	169	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Other Production	38	38	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	Transmission	2,184	0	0	2,176	0	0	0	0	0	0	0	0	0	0	0	8
7	Distribution	5,227	0	0	0	5,214	0	0	0	0	0	0	0	0	0	0	13
	Distribution																
8	Land and Land Clearing	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	Conductors, Poles and Fittings	21,147	0	0	0	0	10,185	5,982	0	0	2,546	1,495	0	0	938	0	0
10	Transformers	4,569	0	0	0	0	0	0	3,290	1,279	0	0	0	0	0	0	0
11	Services	3,285	0	0	0	0	0	0	0	0	0	0	3,285	0	0	0	0
12	Meters	2,523	0	0	0	0	0	0	0	0	0	0	0	2,523	0	0	0
13	Street lighting	1,332	0	0	0	0	0	0	0	0	0	0	0	0	1,332	0	0
	General Plant																
14	Land and Land Rights	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15	Buildings	1,112	67	59	166	91	188	110	59	23	47	28	58	16	29	170	1
16	Computer Equipment	5,286	222	198	594	343	705	414	222	86	176	104	217	61	108	1,834	4
17	Misc. Equipment	650	34	30	125	55	114	67	36	14	29	17	35	10	17	66	1
18	Transportation	2,764	45	40	378	310	637	374	201	78	159	94	196	55	97	96	3
19	Tele-communications	190	12	10	55	15	32	19	10	4	8	5	10	3	5	3	0
20	Total	62,066	4,526	3,338	8,121	6,029	11,861	6,966	3,817	1,484	2,965	1,742	3,800	2,667	2,526	2,170	53

Newfoundland Power Inc.
Pro Forma 2019 Cost of Service Study

FUNCTIONAL CLASSIFACTION OF DEPRECIATION EXPENSES (NET OF AMORTIZED CIAC)

Line No.	Category	Basis for Functional Classification
1	Hydro Electric Production	Classified based on factors shown in Schedule 5.1 Line 4.
2	Other Generation	Classified based on factors shown in Schedule 5.1 Line 5.
3	Transmission	Functional split based on Schedule 5.1 line 19. Common costs Classified based on the transmission common as shown on Schedule 5.1 Line 6.
	Substations	
4	Hydro Electric Production	Functional splits based on Schedule 5.1 line 20 and classified as shown in Schedule 5.1 line 4.
5	Other Production	Functional splits on based Schedule 5.1 line 20 and classified as shown in Schedule 5.1 line 5.
6	Transmission	Functional splits based on Schedule 5.1 line 20 and common transmission costs classified as shown in Schedule 5.1 line 6.
7	Distribution	Functional splits based on Schedule 5.1 line 20 and distribution substation common costs classified as shown in Schedule 5.1 line 7.
	Distribution	
8	Land and Land Clearing	Functional splits based on Schedule 5.1 line 21 and classified as shown in Schedule 5.1 lines 8, 9 & 10.
9	Conductors, Poles and Fittings	Functional splits based on Schedule 5.1 line 22 and classified as shown in Schedule 5.1 lines 11, 12 & 13.
10	Transformers	Classified as shown in Schedule 5.1 line 14.
11	Services	Classified as shown in Schedule 5.1 line 15.
12	Meters	Classified as shown in Schedule 5.1 line 16.
13	Street lighting	Classified as shown in Schedule 5.1 line 17.
	General Plant	
14	Land and Land Clearing	Functionalized based on general property land and land rights (See Schedule 5.1 line 23). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
15	Buildings	Functionalized based on general property buildings and structures (See Schedule 5.1 line 24). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
16	Computer Equipment	Functionalized based on Computer Hardware and Software (See Schedule 5.1 line 25). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
17	General Prop and Other Equip	Functionalized based on General Property Other Equipment (See Schedule 5.1 line 26). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
18	Transportation	Functionalized based on Transportation (See Schedule 5.1 line 27). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
19	Tele-communications	Functionalized based on Total Communications (See Schedule 5.1 line 28). Classification based on total direct Utility plant for each functional category: Production, Transmission, Distribution, Customer Accounting & Customer Service and Specifically Assigned.
20	Total	Total of Lines 1 through 19.

Newfoundland Power Inc.
Pro Forma 2019 Cost of Service Study

CUSTOMER STATISTICS

Line No.	Class of Service	Rate Class	BILLING INFORMATION: Number of Customers At Year End 2018	2019	Average	2019 Energy Sales kWh	2019 Total Billing Demands kW \ kVA	Non-coincident Maximum Class Demands (NCP): Estimated Class Load Factor	Class NCP Demand kW	Class Demand Coincident with System Peak (1CP): Estimated Class Load Factor	Class 1CP Demand kW
			A	B	C	D	E	F	G	H	I
	DOMESTIC										
1	Domestic Regular	1.1	72,194	71,334	71,764	750,728,000	0	43.0%	199,301	51.8%	165,443
2	Domestic All Electric	1.1	160,910	162,798	161,854	2,808,986,000	0	47.9%	669,437	46.8%	685,172
	GENERAL SERVICE										
3	(0-10 kW)	2.1	12,210	12,191	12,201	86,057,000	0	50.9%	19,300	65.2%	15,067
4	(10-100 kW)	2.1	10,514	10,605	10,560	711,568,000	2,750,240	52.6%	154,428	59.7%	136,062
	(110-350 kVA)	2.3									
5	Primary		19	17	18	13,045,166	34,618	56.7%	2,626	68.4%	2,177
6	Secondary		957	965	961	494,089,834	1,666,068	56.7%	99,476	68.4%	82,460
	(350-1000 kVA)	2.3									
7	Transmission		2	1	2	627,808	2,932	56.7%	126	68.4%	105
8	Primary		42	42	42	103,391,876	276,477	56.7%	20,816	68.4%	17,255
9	Secondary		221	243	232	413,006,317	1,187,610	56.7%	83,151	68.4%	68,928
	(1000 kVA and Over)	2.4									
10	Transmission		1	2	2	17,684,111	49,514	66.2%	3,049	74.4%	2,713
11	Primary		30	27	29	268,778,071	598,608	66.2%	46,348	74.4%	41,240
12	Secondary		28	28	28	145,516,818	389,783	66.2%	25,093	74.4%	22,327
13	**STREET LIGHTING**	4.1	10,867	10,793	10,830	33,104,000	0	48.0%	7,873	48.0%	7,873
14	Total		267,995	269,046	268,523	5,846,583,000	6,955,850	50.1%	1,331,027	53.5%	1,246,824

Newfoundland Power Inc.
Pro Forma 2019 Cost of Service Study

ENERGY AND DEMAND LOSS FACTORS[1]

(Losses as a percentage of delivered)

Demand Loss Factors

Transmission	1.3683%
Primary	3.8817%
Secondary	2.9025%

Energy Loss Factors

Transmission	0.8811%
Primary	2.5312%
Secondary	2.2876%

(1) Based on a three year average (2017 to 2019)

Newfoundland Power Inc.
Pro Forma 2019 Cost of Service Study

DEVELOPMENT OF CUSTOMER COST ALLOCATORS

				Customer Related Costs			Primary Lines			Secondary Lines			Transformers			Service Drops			Meters		
Line No.	Class of Service	Rate Code	Average Number of Customers A	Weighting Factor B	Weighted Number of Customer C	Allocation Factors D	Weighting Factor E	Weighted Number of Customer F	Allocation Factors G	Weighting Factor H	Weighted Number of Customer I	Allocation Factors J	Weighting Factor K	Weighted Number of Customer L	Allocation Factors M	Weighting Factor N	Weighted Number of Customer O	Allocation Factors P	Weighting Factor Q	Weighted Number of Customer R	Allocation Factors S
	DOMESTIC																				
1	Domestic Regular	1.1	71,764	1.0	71,764	27.682%	1.0	71,764	26.726%	1.0	71,764	26.735%	1.0	71,764	25.470%	1.0	71,764	27.599%	1.0	71,764	19.203%
2	Domestic All Electric	1.1	161,854	1.0	161,854	62.433%	1.0	161,854	60.277%	1.0	161,854	60.297%	1.0	161,854	57.444%	1.0	161,854	62.245%	1.0	161,854	43.310%
	GENERAL SERVICE																				
3	(0-10 kW)	2.1	12,201	0.9	10,371	4.000%	1.0	12,201	4.544%	1.0	12,201	4.545%	1.2	14,641	5.196%	1.0	12,201	4.692%	2.6	31,723	8.489%
4	(10-100 kW)	2.1	10,560	0.9	9,715	3.747%	1.0	10,560	3.933%	1.0	10,560	3.934%	1.8	19,008	6.746%	1.2	12,672	4.873%	7.2	76,032	20.345%
	(110-350 kVA)	2.3																			
5	Primary		18	0.9	17	0.006%	1.0	18	0.007%	0.0	0	0.000%	0.0	0	0.000%	0.0	0	0.000%	91.2	1,642	0.439%
6	Secondary		961	0.9	884	0.341%	1.0	961	0.358%	1.0	961	0.358%	3.0	2,883	1.023%	1.6	1,538	0.591%	17.7	17,010	4.552%
	(350-1000 kVA)	2.3																			
7	Transmission		2	0.9	2	0.001%	0.0	0	0.000%	0.0	0	0.000%	0.0	0	0.000%	0.0	0	0.000%	166.0	332	0.089%
8	Primary		42	0.9	39	0.015%	1.0	42	0.016%	0.0	0	0.000%	0.0	0	0.000%	0.0	0	0.000%	91.2	3,830	1.025%
9	Secondary		232	0.9	213	0.082%	1.0	232	0.086%	1.0	232	0.086%	3.0	696	0.247%	0.0	0	0.000%	17.7	4,106	1.099%
	(1000 kVA and Over)	2.4																			
10	Transmission		2	0.9	2	0.001%	0.0	0	0.000%	0.0	0	0.000%	0.0	0	0.000%	0.0	0	0.000%	175.9	352	0.094%
11	Primary		29	0.9	27	0.010%	1.0	29	0.011%	0.0	0	0.000%	0.0	0	0.000%	0.0	0	0.000%	138.4	4,014	1.074%
12	Secondary		28	0.9	26	0.010%	1.0	28	0.010%	1.0	28	0.010%	3.0	84	0.030%	0.0	0	0.000%	37.5	1,050	0.281%
13	**STREET LIGHTING**	4.1	10,830	0.4	4,332	1.671%	1.0	10,830	4.033%	1.0	10,830	4.035%	1.0	10,830	3.844%	0.0	0	0.000%	0.0	0	0.000%
14	Total		268,523		259,245	100.0%		268,519	100.0%		268,430	100.0%		281,760	100.0%		260,029	100.0%		373,708	100.0%

NOTES:

Column

A - See Schedule 4.1, Column C.
B - Weighting Factors estimated based on general review of Customer accounting and Customer service activities.
C - Column A times B.
D - Class weighted number of customers divided by the total number of weighted customers for Column C.
E - Equal weighting assigned to all Customers supplied through primary lines.
F - Column A times E.
G - Class weighted number of customers divided by the total number of weighted customers for Column F.
H - Equal weighting assigned to all Customers supplied through secondary lines.
I - Column A times H.
J - Class weighted number of customers divided by the total number of weighted customers for Column I.
K - Weighting reflects customers with three phase supply having a weighting of three while those with single phase supply have a weighting of one.
L - Column A times K.
M - Class weighted number of customers divided by the total number of weighted customers for Column L.
N - Based on typical costs to provide Service Drops for customers within each class.
O - Column A times N.
P - Class weighted number of customers divided by the total number of weighted customers for Column O.
Q - Based on typical cost to provide metering for customers within each class.
R - Column A times Q.
S - Class weighted number of customers divided by the total number of weighted customers for Column R.

Newfoundland Power Inc.
Pro Forma 2019 Cost of Service Study

DEVELOPMENT OF ENERGY ALLOCATORS

Line No.	Class of Service	Rate Code	Secondary Energy Allocator				Primary Energy Allocator				Transmission Energy Allocator			
			Load at Meter kWh	Secondary Energy Loss Factor	Load at Secondary Input kWh	Secondary Allocation Factor	Load at Primary Output kWh	Primary Energy Loss Factor	Load at Primary Input kWh	Primary Allocation Factor	Load at Transmission Output kWh	Transmission Energy Loss Factor	Load at Transmission Input kWh	Transmission Allocation Factor
			A	B	C	D	E	F	G	H	I	J	K	L
	DOMESTIC													
1	Domestic Regular	1.1	750,728,000	0.022876	767,901,654	13.792%	767,901,654	0.025312	787,338,780	12.887%	787,338,780	0.008811	794,276,022	12.848%
2	Domestic All Electric	1.1	2,808,986,000	0.022876	2,873,244,364	51.607%	2,873,244,364	0.025312	2,945,971,925	48.220%	2,945,971,925	0.008811	2,971,928,884	48.074%
	GENERAL SERVICE													
3	(0-10 kW)	2.1	86,057,000	0.022876	88,025,640	1.581%	88,025,640	0.025312	90,253,745	1.477%	90,253,745	0.008811	91,048,971	1.473%
4	(10-100 kW)	2.1	711,568,000	0.022876	727,845,830	13.073%	727,845,830	0.025312	746,269,063	12.215%	746,269,063	0.008811	752,844,440	12.178%
	(110-350 kVA)	2.3												
5	Primary		0	0.022876	0	0.000%	13,240,844	0.025312	13,575,996	0.222%	13,575,996	0.008811	13,695,614	0.222%
6	Secondary		494,089,834	0.022876	505,392,633	9.077%	505,392,633	0.025312	518,185,131	8.482%	518,185,131	0.008811	522,750,860	8.456%
	(350-1000 kVA)	2.3												
7	Transmission		0	0.022876	0	0.000%	0	0.025312	0	0.000%	637,225	0.008811	642,839	0.010%
8	Primary		0	0.022876	0	0.000%	104,942,754	0.025312	107,599,065	1.761%	107,599,065	0.008811	108,547,120	1.756%
9	Secondary		413,006,317	0.022876	422,454,249	7.588%	422,454,249	0.025312	433,147,411	7.090%	433,147,411	0.008811	436,963,873	7.068%
	(1000 kVA and Over)	2.4												
10	Transmission		0	0.022876	0	0.000%	0	0.025312	0	0.000%	17,949,373	0.008811	18,107,525	0.293%
11	Primary		0	0.022876	0	0.000%	272,809,742	0.025312	279,715,102	4.578%	279,715,102	0.008811	282,179,672	4.565%
12	Secondary		145,516,818	0.022876	148,845,661	2.673%	148,845,661	0.025312	152,613,242	2.498%	152,613,242	0.008811	153,957,918	2.490%
13	**STREET LIGHTING**	4.1	33,104,000	0.022876	33,861,287	0.608%	33,861,287	0.025312	34,718,384	0.568%	34,718,384	0.008811	35,024,288	0.567%
14	Total		5,443,055,969	0.022876	5,567,571,317	100.00%	5,958,564,656	0.025312	6,109,387,845	100.000%	6,127,974,442	0.008811	6,181,968,025	100.000%

Newfoundland Power Inc.
Pro Forma 2019 Cost of Service Study

DEVELOPMENT OF ENERGY ALLOCATORS

NOTES:

A - See Schedule 4.1, Column D, Excluding Primary and Transmission Customers.
B - See Schedule 4.2.
C - Estimated Load at Secondary Input including losses. It is equal to Column A times (one plus the loss factor from Column B).
D - Class load relative to the Total Load for Column C.
E - Equal to Column C and includes customers that are supplied at primary level as shown in Schedule 4.1. Energy Sales increased by 1.5% due to reported demand sales being based at secondary sales levels.
F - See Schedule 4.2.
G - Estimated Load at Primary Input including losses. It is equal to Column E times (one plus the loss factor from Column F).
H - Class load relative to the Total Load for Column G.
I - Equal to Column G but includes customers that are supplied at transmission level as shown in Schedule 4.1. Energy Sales increased by 1.5% due to reported energy sales been based at secondary sales levels.
J - See Schedule 4.2.
K - Estimated Load at Transmission Input including losses. It is equal to Column I times (one plus the loss factor from Column J).
L - Class load relative to the Total Load for Column K.

Newfoundland Power Inc.

Pro Forma 2019 Cost of Service Study

DEVELOPMENT OF NON-COINCIDENT PEAK (NCP) DEMAND ALLOCATORS

			Secondary Demand Allocator				Primary Demand Allocator				Transmission Demand Allocator			
Line No.	Class of Service	Rate Code	Load at Meter kW A	Secondary Demand Loss Factor B	Load at Secondary Input kW C	Secondary Allocation Factor D	Load at Primary Output kW E	Primary Demand Loss Factor F	Load at Primary Input kW G	Primary Allocation Factor H	Load at Transmission Output kW I	Transmission Demand Loss Factor J	Load at Transmission Input kW K	Transmission Allocation Factor L
	DOMESTIC													
1	Domestic Regular	1.1	199,301	0.029025	205,086	15.842%	205,086	0.038817	213,047	15.020%	213,047	0.013683	215,962	14.986%
2	Domestic All Electric	1.1	669,437	0.029025	688,868	53.212%	688,868	0.038817	715,608	50.451%	715,608	0.013683	725,399	50.337%
	GENERAL SERVICE													
3	(0-10 kW)	2.1	19,300	0.029025	19,861	1.534%	19,861	0.038817	20,631	1.455%	20,631	0.013683	20,914	1.451%
4	(10-100 kW)	2.1	154,428	0.029025	158,910	12.275%	158,910	0.038817	165,079	11.638%	165,079	0.013683	167,338	11.612%
	(110-350 kVA)	2.3												
5	Primary		0	0.029025	0	0.000%	2,666	0.038817	2,769	0.195%	2,769	0.013683	2,807	0.195%
6	Secondary		99,476	0.029025	102,363	7.907%	102,363	0.038817	106,337	7.497%	106,337	0.013683	107,792	7.480%
	(350-1000 kVA)	2.3												
7	Transmission		0	0.029025	0	0.000%	0	0.038817	0	0.000%	128	0.013683	130	0.009%
8	Primary		0	0.029025	0	0.000%	21,128	0.038817	21,948	1.547%	21,948	0.013683	22,249	1.544%
9	Secondary		83,151	0.029025	85,565	6.609%	85,565	0.038817	88,886	6.267%	88,886	0.013683	90,102	6.252%
	(1000 kVA and Over)	2.4												
10	Transmission		0	0.029025	0	0.000%	0	0.038817	0	0.000%	3,095	0.013683	3,138	0.218%
11	Primary		0	0.029025	0	0.000%	47,043	0.038817	48,869	3.445%	48,869	0.013683	49,538	3.438%
12	Secondary		25,093	0.029025	25,821	1.995%	25,821	0.038817	26,824	1.891%	26,824	0.013683	27,191	1.887%
13	**STREET LIGHTING**	4.1	7,873	0.029025	8,101	0.626%	8,101	0.038817	8,416	0.593%	8,416	0.013683	8,531	0.592%
14	Total		1,258,060	0.029025	1,294,576	100.00%	1,365,413	0.038817	1,418,414	100.000%	1,421,638	0.013683	1,441,090	100.000%

DEVELOPMENT OF NON-COINCIDENT PEAK (NCP) DEMAND ALLOCATORS

NOTES:

A - See Schedule 4.1, Class NCP Demand, Excluding Primary and Transmission Customers.
B - See Schedule 4.2.
C - Estimated Load at Secondary Input including losses. It is equal to Column A times (one plus the loss factor from Column B).
D - Class load relative to the Total Load for Column C.
E - Equal to Column C but includes customers that are supplied at primary level as shown in Schedule 4.1. Class NCP Demand increased by 1.5% due to reported demand sales being based at secondary sales levels.
F - See Schedule 4.2.
G - Estimated Load at Primary Input including losses. It is equal to Column E times (one plus the loss factor from Column F).
H - Class load relative to the Total Load for Column G.
I - Equal to Column G but includes customers supplied at transmission level as shown in Schedule 4.1. Class NCP Demand increased by 1.5% due to reported demand sales been based at secondary sales levels.
J - See Schedule 4.2.
K - Estimated Load at Transmission Input including losses. It is equal to Column I times (one plus the loss factor from Column J).
L - Class load relative to the Total Load for Column K.

DEVELOPMENT OF SINGLE COINCIDENT PEAK (1CP) DEMAND ALLOCATORS

			Secondary Demand Allocator				Primary Demand Allocator				Transmission Demand Allocator			
Line No.	Class of Service	Rate Code	Load at Meter kW	Secondary Demand Loss Factor	Load at Secondary Input kW	Secondary Allocation Factor	Load at Primary Output kW	Primary Demand Loss Factor	Load at Primary Input kW	Primary Allocation Factor	Load at Transmission Output kW	Transmission Demand Loss Factor	Load at Transmission Input kW	Transmission Allocation Factor
			A	B	C	D	E	F	G	H	I	J	K	L
	DOMESTIC													
1	Domestic Regular	1.1	165,443	0.029025	170,245	13.981%	170,245	0.038817	176,854	13.308%	176,854	0.013683	179,273	13.279%
2	Domestic All Electric	1.1	685,172	0.029025	705,059	57.902%	705,059	0.038817	732,427	55.115%	732,427	0.013683	742,449	54.996%
	GENERAL SERVICE													
3	(0-10 kW)	2.1	15,067	0.029025	15,505	1.273%	15,505	0.038817	16,106	1.212%	16,106	0.013683	16,327	1.209%
4	(10-100 kW)	2.1	136,062	0.029025	140,012	11.498%	140,012	0.038817	145,446	10.945%	145,446	0.013683	147,437	10.921%
	(110-350 kVA)	2.3												
5	Primary		0	0.029025	0	0.000%	2,210	0.038817	2,296	0.173%	2,296	0.013683	2,327	0.172%
6	Secondary		82,460	0.029025	84,854	6.968%	84,854	0.038817	88,148	6.633%	88,148	0.013683	89,354	6.619%
	(350-1000 kVA)	2.3												
7	Transmission		0	0.029025	0	0.000%	0	0.038817	0	0.000%	106	0.013683	108	0.008%
8	Primary		0	0.029025	0	0.000%	17,514	0.038817	18,194	1.369%	18,194	0.013683	18,443	1.366%
9	Secondary		68,928	0.029025	70,929	5.825%	70,929	0.038817	73,682	5.545%	73,682	0.013683	74,690	5.533%
	(1000 kVA and Over)	2.4												
10	Transmission		0	0.029025	0	0.000%	0	0.038817	0	0.000%	2,754	0.013683	2,792	0.207%
11	Primary		0	0.029025	0	0.000%	41,858	0.038817	43,483	3.272%	43,483	0.013683	44,078	3.265%
12	Secondary		22,327	0.029025	22,975	1.887%	22,975	0.038817	23,867	1.796%	23,867	0.013683	24,194	1.792%
13	**STREET LIGHTING**	4.1	7,873	0.029025	8,101	0.665%	8,101	0.038817	8,416	0.633%	8,416	0.013683	8,531	0.632%
14	Total		1,183,334	0.029025	1,217,680	100.00%	1,279,262	0.038817	1,328,919	100.000%	1,331,780	0.013683	1,350,003	100.000%

DEVELOPMENT OF SINGLE COINCIDENT PEAK (1CP) DEMAND ALLOCATORS

NOTES:

A - See Schedule 4.1, Class 1CP Demand, Excluding Primary and Transmission Customers.
B - See Schedule 4.2.
C - Estimated Load at Secondary Input including losses. It is equal to Columns A times (one plus the loss factor).
D - Class load relative to the Total Load for Column C.
E - Equal to Column C but includes customers that are supplied at primary level as shown in Schedule 4.1. Class 1CP Demand increased by 1.5% due to reported demand sales being based at secondary sales levels.
F - See Schedule 4.2.
G - Estimated Load at Primary Input including losses. It is equal to Columns E times (one plus the loss factor from Column F).
H - Class load relative to the Total Load for Column G.
I - Equal to Column G but includes customers that are supplied at transmission level as shown in Schedule 4.1. Class 1CP Demand increased by 1.5% due to reported demand sales been based at secondary sales levels.
J - See Schedule 4.2.
K - Estimated Load at Transmission Input including losses. It is equal to Columns I times (one plus the loss factor from Column J).
L - Class load relative to the Total Load for Column K.

FUNCTIONAL CLASSIFICATION SPLITS

Scenarios

Line No.	Utility Plant Category	Total	Produced & Purchased Demand	Produced & Purchased Energy	Transmission Demand	Distribution: Substation Demand	Distribution: Primary Demand	Distribution: Primary Customer	Distribution: Transformers Demand	Distribution: Transformers Customer	Distribution: Secondary Demand	Distribution: Secondary Customer	Distribution: Services Customer	Distribution: Meters Customer	Distribution: St. Lighting Customer
		A	B	C	D	E	F	G	H	I	J	K	L	M	N
	PURCHASED POWER														
1	Purchased Power from Nfld. & Lab. Hydro - Production	100.0%	34.2%	65.8%											
2	Purchased from Nfld. & Lab. Hydro - Transmission	100.0%	100.0%	0.0%											
3	Purchased from Deer Lake Power - Secondary	100.0%	34.2%	65.8%											
	PRODUCTION														
4	Hydro	100.0%	45.7%	54.3%											
5	Other Production	100.0%	100.0%												
	TRANSMISSION														
6	Common	100.0%			100.0%										
	DISTRIBUTION														
7	Substations - Common	100.0%				100.0%									
	Land and Land Use														
8	Primary	100.0%					63.0%	37.0%							
9	Secondary	100.0%									63.0%	37.0%			
10	Street Lighting	100.0%													100.0%
	Conductors, Poles and Fixtures														
11	Primary	100.0%					63.0%	37.0%							
12	Secondary	100.0%									63.0%	37.0%			
13	Street Lighting	100.0%													100.0%
14	Transformers	100.0%							72.0%	28.0%					
15	Services	100.0%											100.0%		
16	Meters	100.0%												100.0%	
17	Street Lights	100.0%													100.0%

MISCELLANEOUS FUNCTIONAL COST ASSIGNMENT FACTORS

Line No.	Cost Item	Total	Production	Transmission
18	Purchased from Nfld. & Labrador Hydro	100.0%	87.8%	12.2%

Line No.		Total	Common	Specifically Assigned
19	Transmission	100.0%	99.49%	0.51%

Line No.		Total	Hydro Producion	Other Production	Total Production	Transmission Common	Transmission Specifically Assigned	Distribution Substation Common	Distribution Specifically Assigned	Cust. Acc. Cust. Serv.
20	Substations	100.0%	4.02%	0.49%	4.50%	28.04%	0.11%	67.19%	0.17%	0.00%

Line No.	Distribution	Distribution Depreciation, Fixed Assets & CIACs: Total	Primary	Secondary	St. Lighting	Distribution Acc. Depreciation: Total	Primary	Secondary	St. Lighting
21	Land and Land Use	100.0%	76.45%	19.11%	4.44%	100.0%	76.17%	19.04%	4.78%
22	Conductors, Poles and Fixtures	100.0%	76.45%	19.11%	4.44%	100.0%	76.17%	19.04%	4.78%

Line No.	General Plant Related Costs		Production	Transmission	Distribution	Cust. Acc. Cust. Serv.
23	Gen. Prop. Land and Land Rights	100.0%	11.39%	14.49%	56.21%	17.91%
24	Gen. Prop. Buildings and Structures	100.0%	11.35%	15.02%	58.34%	15.29%
25	Computer Hardware and Software	100.0%	7.95%	11.28%	46.07%	34.70%
26	Gen. Prop. Other Equipment	100.0%	9.88%	19.34%	60.61%	10.17%
27	Transportation	100.0%	3.11%	13.74%	79.66%	3.49%
28	Communication - Total	100.0%	11.52%	29.26%	57.61%	1.61%
29	Communication - Scada	100.0%	11.52%	16.07%	72.41%	0.00%
30	Communication - Total Expenses	100.0%	5.75%	14.46%	64.52%	15.27%
31	Inventory	100.0%	8.73%	24.80%	66.47%	0.00%

FUNCTIONAL CLASSIFICATION SPLITS

Line No.	Utility Plant Category	Reason for Functional Classification
1	Purchased Power from Nfld. & Lab. Hydro - Production	Classified based on the results, before deficit allocation, of NLH's 2019 test year COS. See NLH's July 11, 2019 Compliance Filing for Rate Setting, Exhibit 14, Schedule 3.2 A.
2	Purchased from Nfld. & Lab. Hydro - Transmission	Classified 100% to Demand
3	Purchased from Deer Lake Power - Secondary	Assumed same classification as Nfld. and Lab. Hydro Production related purchased power allocated to NP.
	PRODUCTION	
4	Hydro	Classified based on island interconnected system load factor from NLH's 2019 test year COS. See NLH's July 11, 2019 Compliance Filing for Rate Setting, Exhibit 14 Schedule 4.2.
5	Other Production	Classified 100% to Demand
	TRANSMISSION	
6	Common	Classified 100% to Demand
	DISTRIBUTION	
7	Substation - Common	Classified 100% to Demand
	Land and Land Use	
8	Primary	Classified between Demand and Customer Based on a minimum system analysis.
9	Secondary	Classified between Demand and Customer Based on a minimum system analysis.
10	Street Lighting	Classified 100% to direct Street Lighting costs.
	Conductors, Poles and Fixtures	
11	Primary	Classified between Demand and Customer Based on a minimum system analysis.
12	Secondary	Classified between Demand and Customer Based on a minimum system analysis.
13	Street Lighting	Classified 100% to direct Street Lighting costs.
14	Transformers	Classified between Demand and Customer Based on a zero intercept method.
15	Services	Classified 100% to Customer
16	Meters	Classified 100% to Customer
17	Street Lights	Classified 100% to Direct Street Lighting.

MISCELLANEOUS FUNCTIONAL COST ASSIGNMENT FACTORS

Line No.	Utility Plant Category	Reason
18	Purchased from Nfld. & Labrador Hydro	Split between production and transmission related purchased power based on results ,before deficit allocation of Nfld. & Lab. Hydro 2019 Test Year Cost of Service. See NLH's July 11,2019 Compliance Filing for Rate Setting, Schedule 3.2A.
19	Transmission	Based on an analysis of 2019 year end fixed plant. Specifically Assigned based on 2019 Data.
20	Substations	Based on an analysis of 2019 year end fixed plant. Specifically Assigned based on 2019 Data.
	Distribution	
21	Land and Land Use	Split between the different functional groups are based on the split for Conductors Poles and Fittings.
22	Conductors, Poles and Fixtures	Functional split based on a study of fixed assets.
23	Gen. Prop. Land and Land Rights	Based on a 2019 General Property Fixed Plant Allocation Study (2019 Data)
24	Gen. Prop. Buildings and Structures	Based on a 2019 General Property Fixed Plant Allocation Study (2019 Data)
25	Computer Hardware and Software	Based on a 2019 General Property Fixed Plant Allocation Study (2019 Data)
26	Gen. Prop. Other Equipment	Based on a 2019 General Property Fixed Plant Allocation Study (2019 Data)
27	Transportation	Based on a 2019 General Property Fixed Plant Allocation Study (2019 Data)
28	Communication - Total	Based on a 2019 General Property Fixed Plant Allocation Study (2019 Data)
29	Communication - Scada	Based on a 2019 General Property Fixed Plant Allocation Study (2019 Data)
30	Communication - Total Expenses	Based on a 2019 General Property Fixed Plant Allocation Study (2019 Data)
31	Inventory	Based on an allocation of the year end inventory for 2019.

Newfoundland Power Inc.
Pro Forma 2019 Cost of Service Study

RECONCILIATION OF EXPENSES WITH ANNUAL REPORT TO BOARD
(All dollars are times 1,000)

The total expenses shown on Schedule 1.1, reflects adjustment of the total reported expenses to *include* depreciation, the amortization of the various Deferrals and *exclude* non-regulated expense, Rural Deficit and certain expenses associated recovered through other revenue (expense credits). Also, Curtailable Service Option credit payments are included as an expense in the Cost of Serivce Study as opposed to a reduction to class revenue from rates as recorded by the Company.

Total Reported Company Expenses	$524,070	(Return 20)
Add		
Depreciation Expense	62,066	(Return 6) (Schedule 1.1, page 1 of 2)
Curtailable Credits	365	(2019 Curtailable Service Option Report)
Amortization - 2019 General Cost Deferral	1,752	(Schedule 3.2, page 1 of 2 line 28)
Pension and OPEBs Variance Deferral	(896)	(Schedule 3.2, page 1 of 2 line 29)
Amortization - Revenue Requirement Shortfall	(145)	(Schedule 3.2, page 1 of 2 line 30)
Pro Forma Purchased Power Increase	59,913	(Newfoundland Power's Application for October 1, 2019 Customer Rates)
Less		
Deduct non-regulated expenses	3,576	(Non regulated Expenses from Return 13 plus tax adjustment from Schedule 5.4)
Other Contract Expenses	4,353	Return 20, line 29
Rural Deficit	61,763	(Schedule 1.1, page 2 of 2)
Expense Credits		
Wheeling Revenues	765	(Schedule 1.1, page 1 of 2)
Joint Use Revenues	2,275	(Schedule 1.1, page 1 of 2)
Revenue from Temp. Services and Reconnects	195	(Schedule 1.1, page 1 of 2)
Customer Service Fees	260	(Schedule 1.1, page 1 of 2)
RSA Transfer - Energy Supply Cost Variance	(3,326)	(Schedule 1.1, page 1 of 2)
RSA Transfer - CDM Revenue Deferral	4,597	(Schedule 1.1, page 1 of 2)
Total Expense Credits	4,766	
Rounding	-	
Total expense before Return and Taxes on Schedule 1.1 Excluding RSA, MTA and the Hydro Rural deficit	$572,667	

Newfoundland Power Inc.
Pro Forma 2019 Cost of Service Study

RECONCILIATION OF REVENUE WITH ANNUAL REPORT TO BOARD
(All dollars are times 1,000)

Revenue from Rates shown on Schedule 1.4 does not include customer billings associated with the RSA and MTA rate adjustments. Also the Curtailable Service Option credit payments are included as an expense in the Cost of Serivce Study as opposed to a reduction to class revenue from rates as recorded by the Company. As a result revenue is increased to remove the impact of the Curtailable Service Option credit payments on revenue.

Revenue from Rates	$684,179	(Return 14)
Wholesale Rate Change Flow-Through	(15,651)	(Return 14)
Add		
RSA Billings	2,514	(Schedule 1.4)
MTA Billings	17,537	(Schedule 1.4)
Curtailable Service Option Credits	365	(2019 Curtailable Service Option Report)
Pro forma Increase in Revenue from Base Rates	59,913	Newfoundland Power's Application for October 1, 2019 Customer Rates
Rounding	-	
Total Revenue from Final Rates	$748,857	(Schedule 1.4)

Newfoundland Power Inc.
Pro Forma 2019 Cost of Service Study

RECONCILIATION OF RETURN AND TAXES WITH ANNUAL REPORT TO BOARD
(All dollars are times 1,000)

Return and Taxes From Annual Report to Board

Return on Rate Base (After adjustment to Regulated Earnings)	$80,427	(Return 13)
Total Income Tax	11,298	(Return 22)
Total Return and Taxes	91,725	
Adjustments		
Tax Adjustment for non-regulated expenses[1].	1,072	
Tax Adjustment for Cost of Removal[2]	5,953	(Return 6, note 2)
Equity component of AFUDC	870	(Return 13 and Return 25)
Other Adjustments		
Interest on security deposits	29	(Return 25)
Adjusted Return and Taxes	99,650	(Schedule 1.1)

Notes:

1. Tax adjustment associated with non-regulated expenses from detail.

Non-regulated expenses	3,576	
Income taxes (Tax Rate 30%)	1,072	
Rounding	-	
Non-regulated expenses net of taxes	2,504	(Return 12)

2. The income tax is adjusted to reflect cost of removal recorded net of taxes for regulatory purposes while the tax impact of the cost of removal is recorded as part of Total Income Tax on Return 22.

Customer Rate Impacts

May 2021

Table of Contents

Page

1.0 Introduction

Newfoundland Power Inc. ("Newfoundland Power" or the "Company") performed an impact analysis on the proposed rates relative to the current rates (effective October 1, 2019) for the Domestic class and for each of the General Service classes.

This report summarizes the results of this analysis.

2.0 Domestic Methodology

2.1 General

There were approximately 233,800 customer accounts billed on the Domestic rate and approximately 1,500 customer accounts billed on the Domestic - Seasonal Optional rate at December 31, 2020. Evaluation of customer impacts of the proposed rate change for the Domestic class was based upon data from a representative sample of customers served under the Domestic rate.

The Domestic rate has the same energy price year-round. Therefore, the billing impacts can be determined based upon annual usage. The sample design methodology focused on ensuring that the annual usage distribution of the sample is reasonably representative of the annual usage of the population.

The Domestic customers identified in the Customer Service System with electricity as their primary heating source ("Domestic All-Electric") were analyzed separately from the Domestic customers identified as having some other heating source ("Domestic Regular"). The billing impacts were determined by applying the existing and proposed rates to the 2020 monthly electricity usage of a sample of 5,943 customers in the Domestic Regular subgroup and 15,011 in the Domestic All-Electric subgroup.[1]

The Domestic samples were selected using a systematic random sampling method to ensure the samples had comparable annual energy usage distributions to the subgroup populations.

The Domestic - Seasonal Optional Rate has approximately 1,500 participants. The impacts of the proposed customer rates were analyzed based upon the usage data of all customers on the rate option for the full year of 2020.

2.2 Sample Reliability

The Domestic samples provide a 95% confidence with ±0.9% relative accuracy on average monthly energy usage for the Domestic All-Electric subgroup and a 95% confidence with ±2.0% relative accuracy on average monthly energy usage for the Domestic Regular subgroup.

The Domestic samples are reasonable for the purpose of evaluating the effects of the proposed rate changes on customer accounts.

[1] The samples represent approximately 10% of the customers in the respective subgroups who were active for all 12 months of 2020.

3.0 General Service Methodology

There were 24,195 General Service customer accounts billed at year-end 2020.

Table 1 provides the breakdown of General Service customer accounts, sales and revenue by rate class.

Table 1:
General Service Classes

Rate	Rate Class	Customer Accounts	Sales (GWh)	Revenue ($000s)
#2.1	0-100 kW (110 kVA)	22,871	749.4	93,282
#2.3	110-1000 kVA	1,265	990.2	105,418
#2.4	1000 kVA and Over	59	410.1	38,643
	Total General Service	**24,195**	**2,149.7**	**237,343**

The Company reviewed the billing impacts for all customer accounts that were on each General Service rate for the full year of 2020.

4.0 Customer Impacts

4.1 Domestic

The overall average revenue increase of 0.8% applies to Domestic Rate #1.1 and Domestic Seasonal Rate #1.1S customers. The proposed 0.8% increase has been applied to Rate #1.1 energy charges. Slightly higher and lower rate increases have been applied to rate components that require the maintenance of specific cost differentials. This includes basic customer charges as well as winter and non-winter energy charges for Rate #1.1S customers.[2]

Table 2 shows the customer bill impacts for Rate #1.1 and #1.1S under the proposed rate.

Table 2:
Domestic #1.1 and #1.1S
Customer Bill Impacts

Annual Impact (%)	Percentage of Customers
0.7	0.0
0.8	100.0
0.9	0.0
Total	**100.0**

2 See *Volume 1, Application, Company Evidence and Exhibits, Section 5.4.2 Changes to Rate Components*.

All Rate #1.1 and #1.1S customers will receive annual bill impacts of 0.8%.

4.2 General Service

The overall average revenue increase of 0.8% applies to General Service Rate #2.1. The proposed 0.8% increase has been applied to Rate #2.1 energy charges. Slightly higher and lower rate increases have been applied to rate components that require the maintenance of specific cost differentials. This applies to basic customer charges for unmetered, single phase, and three phase customers. It also applies to winter and non-winter demand charges.[3]

Table 3 shows the customer bill impacts for Rate #2.1 under the proposed rate.

Table 3:
Rate #2.1
Customer Bill Impacts

Annual Impact (%)	Percentage of Customers
0.5 to 0.7	3.6
0.7 to 0.9	91.8
0.9 to 1.1	3.6
1.1 to 1.3	0.8
1.3 to 1.4	0.2
Total	**100.0**

Approximately 95.4% of Rate #2.1 customers will receive annual bill impacts of between 0.5% to 0.9%. Approximately 4.6% of Rate #2.1 customers will receive an annual bill impact of between 0.9% and 1.4%.

Customers receiving annual bill impacts of greater than 0.9% are unmetered customers with low energy usage. The average annual bill impact for these customers is $4.10. The maximum annual bill impact for these customers is $6.37.

[3] See *Volume 1, Application, Company Evidence and Exhibits, Section 5.4.2 Changes to Rate Components*.

The overall average revenue increase of 0.8% applies to General Service Rate #2.3 customers. The proposed 0.8% increase has been applied to Rate #2.3 energy charges and the basic customer charge. A slightly higher rate increase has been applied to non-winter demand charges and a slightly lower rate increase has been applied to winter demand charges. This is to maintain the specific cost differential between the winter and non-winter demand charges for Rate #2.3 customers.[4]

Table 4 shows the customer bill impacts for Rate #2.3 under the proposed rate.

Table 4:
Rate #2.3
Customer Bill Impacts

Annual Impact (%)	Percentage of Customers
0.7	0
0.8	99.7
0.9	0.3
Total	**100.0**

Approximately 99.7% of Rate #2.3 customers will receive annual bill impacts of 0.8%. Approximately 0.3% of Rate #2.3 customers will receive annual bill impacts of 0.9%.

Customers receiving annual bill impacts of 0.9% experienced relatively low demand in the 2020 winter months compared to the non-winter months. The average annual bill impact for customers receiving an increase of 0.9% is approximately \$276. The maximum annual bill impact for these customers is \$491.[5]

4 See *Volume 1, Application, Company Evidence and Exhibits, Section 5.4.2 Changes to Rate Components*.

5 The average annual bill for customers receiving an increase of 0.9% is approximately \$32,000.

The overall average revenue increase of 0.8% applies to Rate #2.4 customers. The proposed 0.8% increase has been applied to Rate #2.4 energy charges and the basic customer charge. Winter and non-winter demand charges differ slightly from the proposed 0.8% increase to maintain specific cost differentials for those rate components.[6]

Table 5 shows the customer bill impacts for Rate #2.4 under the proposed rate.

Table 5:
Rate #2.4
Customer Bill Impacts

Annual Impact (%)	Percentage of Customers
0.7	14.0
0.8	86.0
0.9	0.0
Total	**100.0**

All customers in Rate #2.4 will receive annual bill impacts of 0.7% or 0.8%. Differences in annual rate impacts are the result of customers' monthly billing demand and the changes to winter and non-winter demand charges required to maintain specific cost differentials between those rate components.

[6] See *Volume 1, Application, Company Evidence and Exhibits, Section 5.4.2 Changes to Rate Components*.

Review of General Expenses Capitalized

May 2021

NEWFOUNDLAND POWER
A FORTIS COMPANY

Table of Contents

Page

1.0 Executive Summary

In February 2021, the Newfoundland and Labrador Board of Commissioners of Public Utilities (the "Board") requested that Newfoundland Power Inc. ("Newfoundland Power" or the "Company") include with its next general rate application a review of its methodology and cost ratios used to determine General Expenses Capitalized ("GEC").

The Board requested that the review address why the Company includes pension costs in GEC and how capitalizing pension costs by way of a labour loader would impact revenue requirement and customer rates.

Newfoundland Power's review determined that, excluding pension costs, the Company's GEC methodology and calculation are consistent with established regulatory principles of the Board and sound public utility practice.

Certain changes to the calculation of GEC are proposed to account for changes in Newfoundland Power's operations since the matter was last considered by the Board in 1999. The proposed changes include removing general expenses for printing services from the GEC calculation, adding general expenses for information systems to the GEC calculation, and revising certain cost ratios used to allocate general expenses to GEC.

These changes to the calculation of GEC are proposed to be effective January 1, 2023 and would decrease 2023 revenue requirement by approximately $0.1 million.

Newfoundland Power proposes to remove pension costs from its GEC calculation and directly charge pension costs to capital projects by way of a labour loader, effective January 1, 2023.

The use of a labour loader to directly charge pension costs to capital projects is consistent with the Company's current treatment of Other Post-Employment Benefit costs and sound public utility practice.

The allocation of pension costs to capital projects by way of a labour loader would increase the 2023 revenue requirement by approximately $1.4 million. This is primarily the result of income tax effects. The estimated customer rate impact of this proposal is an increase of 0.2%.

The income tax effects associated with the proposed change in capitalizing pension costs would reverse over time and reduce revenue requirements in subsequent years. Ultimately, there would be no impact on total revenue requirement collected through customer rates over the lives of the related capital assets.

2.0 Background

2.1 General

On August 14, 2020, Newfoundland Power filed with the Board a *Review of Capitalization Policies and Guidelines* (the "Capitalization Practices Report").[1]

The Capitalization Practices Report concluded that Newfoundland Power's capitalization practices comply with United States generally accepted accounting principles ("U.S. GAAP") and relevant orders of the Board. A survey of 11 Canadian utilities confirmed that the Company's capitalization practices are consistent with sound public utility practice, including the capitalization of general expenses.[2]

On February 16, 2021, the Board commented on the Capitalization Practices Report. The Board acknowledged that Newfoundland Power's GEC methodology was last considered by the Board in 1999 and should be revisited.[3]

The Board requested that Newfoundland Power include a review of its methodology and cost ratios used to determine GEC with its next general rate application.[4] The Board also requested that the review address why the Company is the only utility surveyed that includes pension costs in its GEC and the potential impact on revenue requirement and customer rates if Newfoundland Power capitalized pension costs by way of a labour loader.

2.2 Current GEC Methodology

Newfoundland Power follows the incremental cost method to allocate general expenses to GEC. Use of the incremental cost method to allocate general expenses to GEC was approved by the Board in Order No. P.U. 3 (1995-96) (the "GEC Order").[5]

Consistent with the GEC Order, only costs that vary with the level of capital work, as compared to no capital program whatsoever, are allocated to GEC. Otherwise, costs are expensed as incurred.[6]

---

1 See Attachment 1 for a copy of the Capitalization Practices Report.

2 See Attachment 1, Appendix E for the survey results.

3 Section 58 of the *Public Utilities Act* states that the Board may prescribe the form of all books, accounts, papers and records to be kept by a public utility. Section 78(2)(h) of the *Public Utilities Act* states that, in fixing a rate base, the Board may include other fair and reasonable expenses that: (i) the Board thinks appropriate and basic to the public utility's operation; and (ii) have, with the approval of the Board, been charged to a capital account.

4 The Board's correspondence, dated February 16, 2021, stated: *"The Board is requesting that Newfoundland Power include a review of its methodology and general expense cost ratios used to determine GEC in its general rate application that is scheduled to be filed on June 1, 2021. This will provide the Board with the opportunity to revisit the methodology, and determine if the cost ratios used to allocate cost are appropriate or whether any changes may be warranted for the benefit of rate payers."*

5 In the GEC Order, the Board stated: "*Overhead costs will be considered to be incremental costs of capital projects to the extent that they vary with the level of construction as compared to no capital projects whatsoever. Otherwise the overhead costs are expenses of the period in which they are incurred."* See Order No. P.U. 3 (1995-96), page 28.

6 See Order No. P.U. 3 (1995-96), page 28.

Newfoundland Power's allocation of general expenses to GEC is, in effect, a 3-step process:

(i) The first step requires identifying which general expenses would vary if there was no capital program whatsoever. The general expenses currently included in the calculation of GEC are outlined in the GEC Order.[7] This includes general expenses related to capital planning, operating supervision, tools, equipment and safety clothing, system operations and certain non-construction activities.

(ii) The second step involves determining the amount of each general expense to be allocated to GEC. Ratios are applied to each general expense based on how the expense would vary if there was no capital program whatsoever.[8] For example, capital planning is only required due to the capital program. All general expenses for capital planning are therefore allocated to GEC.

(iii) The third step involves allocating the total GEC amount across capital projects. The total GEC amount is allocated across capital projects using a flat rate. The flat rate is calculated by dividing the total GEC amount by the total capital expenditures.[9] The flat rate is then applied to the cost of each capital project to determine the amount of GEC allocated to that project. For example, the flat rate was 7.93% in 2020 and distribution capital expenditures totaled $42.4 million. Approximately $3.4 million of GEC was therefore allocated to distribution projects in 2020.[10]

2.3 Current Utility Practice

The capitalization of general expenses is a generally accepted accounting practice in the electric utility industry. For example, the *Federal Energy Regulatory Commission* ("*FERC") Uniform System of Accounts* provides for the capitalization of all overhead construction costs, such as engineering, supervision and general office salaries and expenses.[11]

Under U.S. GAAP, rate-regulated entities are permitted to capitalize costs that would otherwise be expensed in the year incurred, where such treatment is approved by the utility regulator. In other jurisdictions, such capitalized expenses may be referred to as "Capitalized Overheads."

A 2020 survey of Canadian utilities confirmed that the capitalization of general expenses is standard industry practice. Of 11 responding utilities, 7 employ an approach similar to that of Newfoundland Power for the capitalization of overhead costs.[12]

---

7 See Order No. P.U. 3 (1995-96), pages 16-22.
8 In Order No. P.U. 36 (1998-99), the Board stated that any adjustments to the GEC ratios are intended to be at the discretion of Newfoundland Power.
9 The GEC Order provided that GEC should be allocated to capital assets on a flat rate basis. The flat rate is determined in a given year by dividing the annual GEC amount by the total capital expenditures in that year, adjusted for projects that are work-in-progress.
10 $42.4 million x 7.93% = $3.4 million.
11 See section 4 of the *FERC Uniform System of Accounts – Electric Plant Instructions*.
12 See Attachment 1, Appendix E, Page E-3, Question 5.

The method used to determine capitalization rates varied among surveyed utilities.[13] Capitalization rates ranged from 1.6% to 26% in 2019. The average capitalization rate of surveyed utilities was 10%.[14]

Newfoundland Power's capitalization rate is comparable to that of other utilities. Excluding pension costs, the Company's overall capitalization rate was 9% in 2019.[15]

3.0 Review of GEC Methodology

3.1 General

Newfoundland Power reviewed its approach to GEC to determine its continued appropriateness and any necessary changes. The review considered:

(i) The basis of the GEC methodology;
(ii) Which general expenses are appropriate to include in the calculation of GEC; and
(iii) The ratios applied to determine the portion of general expenses allocated to GEC.

Section 3 provides the results of Newfoundland Power's review of its approach to GEC.

The capitalization of pension costs was reviewed separately. The results of the review of pension costs are provided in section 4.

3.2 Comparison of Methodologies

There are 2 standard methodologies that can be applied when capitalizing general expenses:

(i) The incremental cost method capitalizes only those general expenses that are incremental to a utility as a result of its capital program.

(ii) The full cost method capitalizes any general expenses incurred in connection with a capital program, including expenses that benefit both a utility's operations and its capital program.

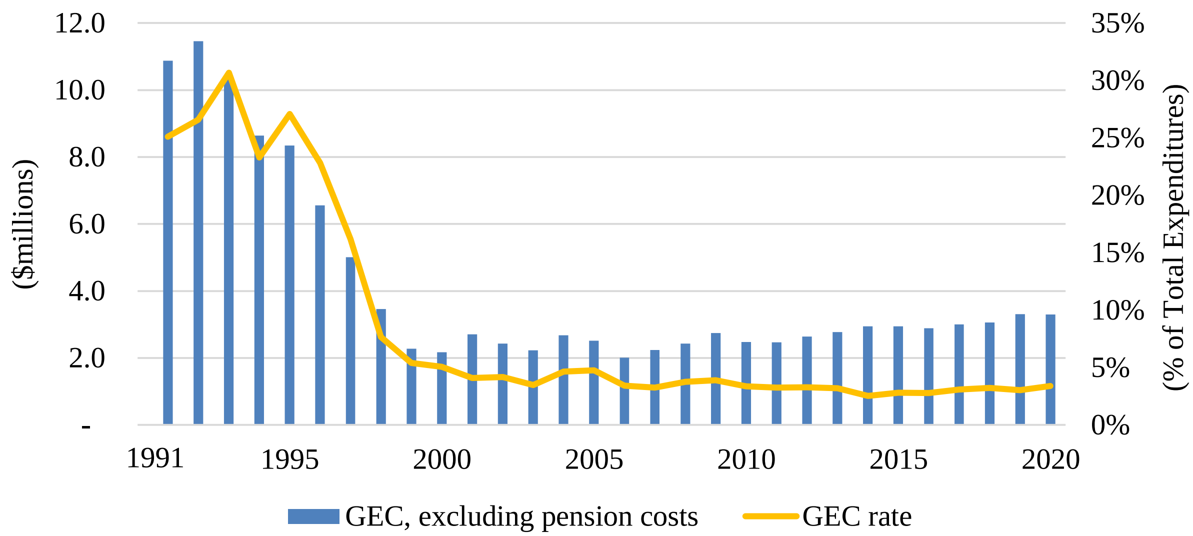
For example, Newfoundland Power's Internal Audit function performs work related to the Company's operations and its capital program. The full cost method would capitalize a portion of Internal Audit costs. However, there would be no material reduction in the work requirements of Internal Audit in the absence of a capital program. The incremental cost method would therefore not capitalize any costs associated with this function.

13 Of the 7 responding utilities, 5 utilities use the full cost method to allocate general expenses and 2 utilities use the incremental cost method. The types of overhead costs capitalized vary among respondents.
14 Two utilities responded "N/A." See Attachment 1, Appendix E, Page E-3, Question 7 ((13.8 + 5.1 + 10.0 + 9.0 + 2.5 + 26.0 + 1.6 + 10.0 + 12.0) / 9 = 10.0).
15 Of the 9.0% capitalization rate, 3.1% related to GEC and the remaining 5.9% related to capitalized interest and vehicle and inventory overheads. See Attachment 1, Appendix E, Page E-3, footnote 1.

Prior to 1995, Newfoundland Power used the full cost method to allocate general expenses to GEC. The Company implemented the incremental cost method in 1999, following a 5-year phase in period.[16]

Figure 1 shows Newfoundland Power's GEC amounts over the period 1991 to 2020, expressed both in dollars and as a percentage of total capital expenditures.[17]

Figure 1:
GEC Amounts
1991 to 2020



Using the full cost method, GEC averaged approximately $10.3 million annually, or 26% of total capital expenditures, from 1991 to 1995. GEC amounts ranged from approximately $8.3 million to $11.5 million annually using the full cost method, or from 23% to 31% of total capital expenditures.

Using the incremental cost method, GEC averaged approximately $2.7 million annually, or 3.5% of total capital expenditures, from 2000 to 2020. GEC amounts ranged from approximately $2.1 million to $3.1 million annually using the incremental cost method, or from 2.6% to 5.0% of total capital expenditures.

Newfoundland Power considered the appropriateness of continuing to apply the incremental cost method from 3 perspectives.

---

[16] In the interest of rate stability for customers, the Board ordered that the new GEC methodology be phased in over a 5-year period from 1995 to 1999. See Order No. P.U. 3 (1995-96).

[17] The GEC amounts exclude pension costs.

First, the Company considered the regulatory principle of customer rate stability.[18] Stability in capital expenditures is conducive to stability in customer rates. The incremental cost method results in a reasonably stable amount of capitalization for general expenses on a year-over-year basis.

Second, Newfoundland Power considered the principle of intergenerational equity.[19] General expenses that are incremental due to the capital program exist only to bring assets into service that provide an enduring benefit to customers. The incremental cost method allocates these costs to GEC so that the costs are recovered over the useful service lives of the related capital assets. This ensures costs are recovered only from customers who benefit from the service provided by those capital assets.

Third, the Company considered current Canadian utility practice. As described in section 2.3, the incremental cost method has provided for capitalization rates that are reasonably consistent with other Canadian utilities.

Based on this review, use of the incremental cost method to allocate general expenses to GEC continues to be appropriate.

3.3 General Expenses

The GEC Order provided guidelines on which general expenses are to be allocated to GEC. Newfoundland Power reviewed its operations to determine whether any changes are required to the general expenses allocated to GEC.

The review confirmed that all general expenses included in the Company's calculation of GEC remain appropriate, with the exception of those related to printing services. The reduction in printing services would be immaterial if there was no capital program. This is largely due to the digitization of forms for capital projects since the 1990s.[20] It is therefore appropriate to remove general expenses for printing services from the calculation of GEC.

The review also determined that certain general expenses related to information systems should be included in the calculation of GEC. Information systems have become integral to Newfoundland Power's operations since the 1990s. There would be lower work requirements associated with information systems if there was no capital program. Specifically, there would be lower work requirements related to information systems planning, including software enhancements and system upgrades. There would also be lower work requirements associated

---

[18] The principle of customer rate stability establishes that rates and revenues should be stable and predictable from year to year, with a minimum of unexpected changes seriously adverse to either ratepayers or the utility. The principle of customer rate stability has been previously recognized by the Board. See, for example, Order No. P.U. 14 (2004), page 24.

[19] The principle of intergenerational equity establishes that customers in a given period should pay only the costs necessary to provide them with service in that period. They should not be required to pay for costs incurred to provide service to customers in another period. The principle of intergenerational equity has been previously recognized by the Board. See, for example, Order No. P.U. 14 (2015), page 12.

[20] Approximately $37,000 of printing services expenses were allocated to GEC in 2020. Printing services primarily relate to customer service requirements, such as printing customer bills.

with providing technical support for information systems, as the Company would have fewer employees and fewer personal computers.

All general expenses proposed to be included in the calculation of GEC, including information systems, are consistent with the definition of Capitalized Overheads in the FERC System of Accounts and reflect sound public utility practice.[21]

Appendix A provides the detailed review of general expenses.

3.4 GEC Ratios

Newfoundland Power reviewed the cost ratios used to allocate general expenses to GEC ("GEC ratios"). The review indicated that certain changes to GEC ratios would be appropriate to better reflect the Company's current operations.

Appendix B provides the detailed review of the GEC ratios, which is summarized below.

Capital Planning

Capital planning general expenses would not exist if there was no capital program. Capital planning general expenses are currently charged directly to GEC. Directly charging capital planning general expenses to GEC continues to be appropriate.

Operating Supervision

Operating supervision requirements would be lower if there was no capital program. This is because Newfoundland Power would have fewer employees and would consolidate regional work tasks if there was no capital program.[22]

The existing GEC ratio of 15% for operating supervision was based on an assessment of the number of regional employees that would no longer be required if there was no capital program. In 1999, it was estimated that approximately 7 regional employees would no longer be required if there was no capital program. This equated to approximately 15% of operating supervision general expenses.[23]

---

[21] Section 4 of the *FERC Uniform System of Accounts – Electric Plant Instructions* provides for the capitalization of all overhead construction costs, such as engineering, supervision and general office salaries and expenses.

[22] In 2020, there were 611.5 full-time equivalents ("FTEs"), of which 214 FTEs were attributed to completing capital work.

[23] Regional employees are employees who work in 1 of the Company's 3 operating regions: St. John's region, Eastern region and Western region.

In 2020, it is estimated that approximately 7 regional employees would no longer be required if there was no capital program.[24] Maintaining the GEC ratio of 15% for operating supervision is therefore appropriate.[25]

Tools, Equipment and Safety Clothing

Tools, equipment and safety clothing requirements would be lower if there was no capital program.

The existing GEC ratio of 48% reflected the percentage of Newfoundland Power's regional labour that was related to capital work in 1999.

In 2020, the percentage of Newfoundland Power's regional labour related to capital work is 65%.[26] Adjusting the GEC ratio for tools, equipment and safety clothing to 65% is therefore appropriate.

System Operations

System operations requirements would be lower if there was no capital program. As examples, the System Control Centre ("SCC") would no longer be required to complete switching orders, protection guarantees, or isolation and grounding requirements related to capital work.

General expenses for system operations are currently charged directly to GEC.

Newfoundland Power estimates there would be a reduction of 2 FTEs in the SCC if there was no capital program.[27] A reduction of 2 FTEs represents a reduction of 10% in the operating costs for system operations.[28] Applying a GEC ratio for system operations of 10% is therefore appropriate.

---

24 The 7 positions are: (i) 1 supervisor; (ii) 1 analyst; (iii) 4 engineering technologists; and (iv) 1 area customer representative.

25 Operating supervision general expenses were $4,431,000 in 2020. Applying a GEC ratio of 15% results in a GEC allocation amount of $665,000. Dividing this amount by 7 employees equates to an average labour cost per FTE of $95,000. This figure is comparable to the Company's overall labour cost per FTE of approximately $106,000 in 2020.

26 This percentage is based on the Company's regional labour allocation. It includes 54% in labour charged to capital projects and 11% in labour charged to retirement projects. Labour charged to retirement projects reflects the amount of time associated with removing plant from service.

27 The SCC is required to operate 24 hours a day. Currently, the Company employs 4 teams of 3 Power System Operators in the SCC. If there was no capital program, the Company would reduce its Power System Operators to 4 teams of 2, plus 2 relief workers required for breaks, vacation and unplanned leave. This represents a reduction from 12 to 10 Power System Operators, or 2 FTEs.

28 System operations general expenses were approximately $2,156,000 in 2020. Applying a GEC ratio of 10% results in a GEC allocation amount of $216,000. Dividing this amount by the Company's overall labour cost per FTE of approximately $106,000 in 2020 equates to 2 FTEs.

Non-Construction Activities

Finance, human resources and information systems requirements would be lower if there was no capital program.[29]

Given the nature of these departments, it is challenging to estimate a specific reduction in general expenses that would occur if there was no capital program. The Board has suggested the use of a nominal rate of 10% as a reasonable proxy in these circumstances.[30]

Adjusting the GEC ratio for these non-construction activities to a nominal rate of 10% is therefore appropriate.

3.5 Summary of Proposed Changes

Newfoundland Power's GEC methodology is consistent with established regulatory principles of the Board and sound public utility practice.

Three minor changes to the calculation of GEC are proposed to account for changes in the Company's operations since the matter was last considered by the Board in 1999. These are:

(i) Removing general expenses for printing services from the GEC calculation;
(ii) Adding general expenses for information systems to the GEC calculation; and
(iii) Adjusting the GEC ratios for tools, equipment and safety clothing, system operations, and non-construction activities.

Newfoundland Power completed a *pro forma* analysis to assess the appropriateness of the proposed changes to its calculation of GEC.

[29] See Appendix B, Section 3.0 Non-Construction Activities for further details on these departments, including work requirements.
[30] See Order No. P.U. 3 (1995-96), page 19.

Table 1 summarizes the results of the *pro forma* analysis of the proposed changes to the calculation of GEC.

Table 1:
GEC Ratios and Amounts

General Expense	Existing Ratios	2020 Actual ($000s)	Revised Ratios	2020 *Pro Forma* ($000s)
<u>Construction Activities</u>				
Capital Planning	Direct	805	Direct	805
Operating Supervision[31]	15%	558	15%	665
Tools, Equipment and Safety Clothing	48%	745	65%	1,009
System Operations	Direct	598	10%	216
Subtotal		**2,706**		**2,695**
<u>Non-Construction Activities</u>				
Finance	13%	243	10%	187
Human Resources	13%	304	10%	252
Information Systems	-	-	10%	317
Employee Welfare[32]	31%	57	-	-
Printing Services[33]	13%	37	-	-
Subtotal		**641**		**756**
Total GEC		**3,347**		**3,451**

The proposed changes to the calculation of GEC do not materially change the total amount allocated to GEC. The total GEC amount incurred in 2020 using the existing calculation was approximately $3,347,000. The *pro forma* GEC amount based on the proposed changes is approximately $3,451,000.

As there is no material change in the total amount capitalized, the proposed changes to the calculation of GEC will continue to provide an overall capitalization rate that is consistent with current utility practice.[34]

---

[31] The existing calculation only includes the Account 52000 – Supervisory and Administrative Support. The revised calculation adds Account 52050 – Engineering and Technical Support. Both accounts include charges associated with Administrative and Engineering Support. See Appendix A, page 1 and Appendix B, page 2.

[32] Employee welfare expenses are proposed to be grouped with human resources expenses. See Appendix B.

[33] Printing services are proposed to be removed from the GEC calculation. See Appendix A.

[34] See Attachment 1, Appendix E, Page E-3, Question 7. Expressed as a percentage, overhead construction costs averaged 10% among the survey respondents in relation to the utilities' total capital expenditures in 2019. This compares to 9% for Newfoundland Power (adjusted to remove the impact of pension costs). Capitalized overhead for Newfoundland Power includes GEC, Allowance for Funds Used During Construction ("AFUDC"), and vehicle and inventory overheads.

Newfoundland Power proposes to implement the identified changes to its calculation of GEC effective January 1, 2023.[35]

The proposed changes to the calculation of GEC will reduce the Company's 2023 revenue requirement by approximately $0.1 million.

4.0 Pension Capitalization

4.1 Allocation Methodology

Newfoundland Power's GEC calculation presently includes a portion of current service costs associated with its pension plans.[36] The GEC calculation allocates 46% of these pension costs to GEC in accordance with Order No. P.U. 2 (2019).[37]

Pension costs are employee benefits that are directly related to labour. Under U.S. GAAP, these costs are to be capitalized similar to labour costs necessary to complete capital work. The appropriateness of capitalizing pension costs is therefore not in question.

The allocation of pension costs directly to capital projects by way of a labour loader is an alternative to the current practice of allocating pension costs to capital projects through GEC.[38] The use of a labour loader is consistent with the Company's current approach for allocating Other Post-Employment Benefit ("OPEB") costs to capital projects.

Conceptually, there is no material difference to total capital expenditures whether pension costs are capitalized by way of a labour loader or through GEC. Both approaches ultimately allocate pension costs to capital projects based on the Company's overall labour allocations.

The use of a labour loader would result in a more accurate allocation of general expenses to capital projects. This is because a labour loader would follow the labour that is directly charged to a capital project, whereas the GEC calculation uses a flat rate to allocate the total GEC amount across capital projects.

---

[35] Newfoundland Power currently expects an order to be issued for its *2022/2023 General Rate Application* in early 2022 to enable the implementation of changes to customer rates effective March 1, 2022. This is consistent with timing of the order issued following the Company's last general rate application, which was filed during a similar time of year. Implementing the proposed changes to GEC part way through 2022 would be administratively complex as general expenses incurred throughout the year would be allocated to GEC on different bases. An effective date of January 1, 2023 would mitigate these administrative complexities.

[36] Current service costs relate to the Company's defined benefit and defined contribution pension plans.

[37] The 46% is based on the Company's overall labour allocation in its 2020 test year. The 46% includes 36% in labour charged to capital projects and 10% in labour charged to retirement projects and rechargeable accounts. Labour charged to retirement projects reflects the time associated with removing plant from service. Rechargeable accounts include time charged to the inventory and vehicle overhead accounts, which are primarily reallocated to capital projects.

[38] A labour loader involves a loading rate being applied to a base labour cost as a method of allocating certain costs to the same general ledger account as the base labour cost. Loading rates are assessed on an annual basis to ensure they are reasonably allocating the total overhead cost. Any over or under-recovery of allocated costs versus the total cost is trued up at year end. Using a labour loader to allocate costs is a standard practice.

The use of a labour loader to directly charge pension costs to capital projects is consistent with current utility practice. Based on the survey conducted in 2020, 10 of 11 responding utilities capitalize pension costs by way of a labour loader.[39]

Removing pension costs from the GEC calculation and directly charging pension costs to capital projects by way of a labour loader is consistent with sound public utility practice and the treatment of Newfoundland Power's OPEB costs.

The Company proposes to implement this change effective January 1, 2023.[40]

4.2 Revenue Requirement Effects

Directly charging pension costs to capital projects by way of a labour loader will increase the 2023 revenue requirement, primarily due to income tax effects.

For income tax purposes, GEC is recognized as an expense in the year incurred. This results in a tax deduction in the initial year of the GEC calculation. However, the annual depreciation expense associated with GEC must be added back to taxable income each year over the lives of the related capital assets. The add back increases income taxes each year and ensures the expense is not deducted twice for tax purposes.[41]

By removing pension costs from the GEC calculation, the associated tax deduction for this portion of GEC will no longer exist in 2023. The annual depreciation expense for this portion of GEC will also no longer exist in subsequent years.

---

[39] See Attachment 1, Appendix E, Page E-3, Question 5a.

[40] Newfoundland Power currently expects an order to be issued for its *2022/2023 General Rate Application* in early 2022 to enable the implementation of changes to customer rates effective March 1, 2022. Implementing the proposed change to the capitalization of pension costs part way through 2022 would be administratively complex as costs incurred throughout the year would be capitalized on different bases. An effective date of January 1, 2023 would mitigate these administrative complexities.

[41] Typically, deferred income tax calculations counteract these timing effects to ensure there is no impact on annual revenue requirement. However, the approved deferred income tax mechanism related to plant investment explicitly excludes GEC from the calculation. In accordance with Order No. P.U. 17 (1987), GEC has been excluded from post-1986 additions to plant in determining depreciation expense for the Plant Investments deferred income taxes calculation. See, for example, Newfoundland Power's *2020 Annual Report* filed with the Board, *Return 23 Accumulated Deferred Income Taxes.*

Table 2 provides the change in 2023 revenue requirements based on capitalizing pension costs by way of a labour loader.

Table 2:
2023 Revenue Requirement
Pension Capitalization – Labour Loader
($000s)

Pension Costs – General Expenses	-
Income Taxes – Change in Pension Capitalization	999
Change in 2023 Revenue Requirement Before Income Taxes	**999**
Income Taxes - Change in Revenue Requirement	428
Total Change in 2023 Revenue Requirement	**1,427**

By capitalizing pension costs by way of a labour loader, approximately $3.4 million in pension costs will be removed from GEC in 2023. The associated tax deduction will therefore not exist in 2023. This will increase income taxes included in the 2023 revenue requirement by approximately $999,000.[42]

The increase in revenue requirement resulting from this proposal will be subject to taxation.[43] As a result, the total increase in revenue requirement in 2023 is approximately $1.4 million.

By removing pension costs from GEC, the associated annual add back for depreciation expense will also not exist. This will decrease revenue requirements in each subsequent year. Ultimately, there would be no impact on revenue requirement over the total lives of the related capital assets.[44]

Appendix C illustrates the income tax effects on 2023 revenue requirement resulting from capitalizing pension costs via GEC versus a labour loader.

Appendix D illustrates the income tax effects resulting from capitalizing pension costs via GEC versus a labour loader.

[42] Appendix C shows the calculation of the increase in income taxes of $999,000. Appendix C also shows that, by allocating pension costs by way of a labour loader, the deferred income tax calculations for both plant investment and pension costs will operate to offset any timing differences that may arise as a result of pension expense recognition for financial reporting and income tax purposes.

[43] The increase in revenue requirement of $999,000 will attract income tax expense of $428,000. Therefore, the total revenue requirement is $1,427,000 (999,000 / (1 – 30%) = 1,427,000 x 30% = 428,000).

[44] The decrease in revenue requirement of $999,000 in subsequent years will result in an associated income tax reduction of $428,000. Therefore, the revenue requirement decrease over the period will total $1,427,000. (999,000 / (1 – 30%) = 1,427,000 x 30% = 428,000).

Review of General Expenses

Review of General Expenses

Expense Description	**Account Number**	**Does the expense vary with the level of construction as compared to no capital projects whatsoever?**	**Include in GEC calculation?**	**Notes**
Power Purchased	500xx	No	No	
Transfer (to) From Rate Stabilization Account	50004	No	No	
Power Produced				
Generation Plan	510xx	No	No	
Hydro Production	512xx	No	No	
Internal Combustion Plants	513xx	No	No	
Wind Turbines	514xx	No	No	
Administrative and Engineering Support				
Supervisory and Administrative Support	52000	Yes	Yes	1
System Operations	522xx	Yes	Yes	2
Tools, Equipment, Safety Clothing and Company Uniforms	525xx	Yes	Yes	3
Engineering and Technical Support	52050	Yes	Yes	4
Environmental Policy	53xxx	No	No	
Substations	54xxx	No	No	
Transmission				
Line Maintenance and Repairs	550xx	No	No	
Line Inspections	554xx	No	No	
Line Vegetation Management	555xx	No	No	
Distribution				
Repair / Maintain Lines	561xx	No	No	
Repair / Maintain Services	563xx	No	No	
Repair / Maintain Street Lights	564xx	No	No	
Pre-Issue of Materials	565xx	Yes	No	5
Maintain Transformers	566xx	No	No	
Maintain Meters	567xx	No	No	
Line Inspections	574xx	No	No	
Line Vegetation Management	577xx	No	No	

Expense Description	Account Number	Does the expense vary with the level of construction as compared to no capital projects whatsoever?	Include in GEC calculation?	Notes
Telecommunications				
Supervision and Miscellaneous	580xx	No	No	
Repeater Sites	581xx	No	No	
Mobile Radios	582xx	No	No	
Communication Cables	583xx	No	No	
Leased Facilities	584xx	No	No	
Supervisory Control Systems	585xx	No	No	
Telephone Systems	586xx	No	No	
Wide Area Networks	587xx	No	No	
Customer Service				
Supervision and Miscellaneous	605xx	No	No	
Customer Accounting	607xx	No	No	
Credit and Collections	608xx	No	No	
Call Centre	609xx	No	No	
Curtailable Rates	62550	No	No	
Conservation Programs and Energy Services Costs	626xx-629xx	No	No	
Uncollectible Bills	61521	No	No	
Financial Services				
Finance	612xx	Yes	Yes	6
Risk Management	615xx	No	No	
Amortization of Conservation Costs	690xx	No	No	
Pension Costs	642xx	Yes	No	7
Other Post Employment Benefits	643xx	Yes	No	5
Information Systems				
Supervision and Miscellaneous	630xx	Yes	Yes	8
Computer Operations	631xx	Yes	Yes	8
Systems Development and Support	632xx	Yes	Yes	8
Infrastructure	633xx	Yes	Yes	8
Corporate and Employee Services				
Printing Services	617xx	Yes	No	9
Corporate Communications	621xx	No	No	

Expense Description	Account Number	Does the expense vary with the level of construction as compared to no capital projects whatsoever?	Include in GEC calculation?	Notes
Corporate Offices	650xx	No	No	
Internal Audit	65300	No	No	
Miscellaneous Administrative Costs	655xx	No	No	
Mail Costs	61610	No	No	
Regulatory and Legal Affairs	65700	No	No	
Human Resources Planning and Administration	64020	Yes	Yes	6
Health, Safety and Training	6403x	Yes	Yes	6
Employee Relations	64040	Yes	Yes	6
Miscellaneous Employee Related Costs	64xxx	Yes	Yes	10
Building Operations and Maintenance	67xxx	No	No	
Municipal Taxes and PUB Assessments	656xx	No	No	
Vehicle Operating and Maintenance Costs	59000	Yes	No	5
Vehicle Service Centre	37xxx	Yes	No	5

1 Currently included in GEC calculation (operating supervision - 15%).

2 Portion currently included in GEC calculation (direct charges).

3 Currently included in GEC calculation (48%).

4 To add to GEC calculation (with operating supervision).

5 Directly charged to capital projects.

6 Currently included in GEC calculation (13%).

7 To remove from GEC calculation and directly charge to capital projects.

8 With no capital program, there would be lower work requirements associated with planning information systems related solutions, including software enhancements and upgrades. There would also be lower work requirements associated with providing technical support given the reduction in employees and thus personal computers. General expenses associated with these activities are proposed to be added to the GEC calculation (10%). In addition, if there were no capital program there would be no general implementation expenses associated with specific capital projects being implemented. General implementation expenses relate to data conversion, employee training and activities related to the procurement process. General implementation expenses can be directly charged to the specific information system capital project. Therefore, these costs do not need to be included in the GEC calculation.

9 While activity may vary, the reduction in general expenses would be small if there were no capital program. General expenses associated with this activity are proposed to be removed from GEC.

10 Portion currently included in GEC calculation (31%).

Review of GEC Ratios

Review of GEC Ratios

Table of Contents

Page

1.0 Introduction

Appendix A identifies the general expenses proposed to be included in the GEC calculation.

The following provides a review of each general expense to determine the appropriate cost ratios to be applied in allocating these general expenses to GEC.[1]

2.0 Construction Activities

2.1 Capital Planning

Capital planning general expenses include labour expenses associated with capital planning activities. This includes engineering reviews conducted as part of long-term asset management strategies and the development of the Company's 5-year capital plan.[2] While capital planning primarily includes internal labour, contractor labour may also be used for capital planning.

Capital planning general expenses exist only as a result of Newfoundland Power's capital program. Without a capital program, refurbishment and rebuild strategies would not be required and a 5-year capital plan would not exist. Capital planning general expenses are therefore directly charged to GEC.

Directly charging general expenses for capital planning to GEC continues to be appropriate.

2.2 Operating Supervision

Operating supervision general expenses include labour costs associated with operating the electrical system. These general expenses cannot properly be allocated to any specific work order or account number.[3]

Operating supervision general expenses would be lower if there was no capital program. This is because, without a capital program, the Company would reduce its number of employees and consolidate regional work tasks.[4]

The existing GEC ratio of 15% for operating supervision was based on an assessment of the number of regional employees that would no longer be required if there was no capital program. At the end of the phase-in period in 1999, it was estimated that approximately 7 regional

---

[1] In Order No. P.U. 36 (1998-99), the Board stated that: *"in P.U. 3 (1995-96), the Board recognized that the company would have to determine how specific general expense cost ratios may have to be adjusted over the period of the five year phase-in from a full cost basis to an incremental cost basis and, thereafter, any adjustments to the ratios was intended to be at the discretion of NP."* See page 26.

[2] Examples of long-term asset management strategies include the Company's: (i) *Substation Strategic Plan*; (ii) *Transmission Line Rebuild Strategy*; and (iii) *Distribution Reliability Initiative*.

[3] See Newfoundland Power's System of Accounts dated March 31, 2021, paragraph 7.07, page 33 and paragraph 7.11, page 34.

[4] In 2020, there were 611.5 full-time equivalents ("FTEs"), of which 214 FTEs can be attributed to completing capital work.

employees would no longer be required if there was no capital program. This translated to approximately 15% of operating supervision general expenses.[5]

In 2020, it is estimated that approximately 7 regional employees would no longer be required if there was no capital program.[6] The GEC ratio of 15% continues to reasonably reflect the reduction in general expenses associated with the reduction in employees if there was no capital program.[7]

Maintaining the GEC ratio of 15% for operating supervision is appropriate.

2.3 Tools, Equipment and Safety Clothing

Tools, equipment and safety clothing general expenses include the repair and replacement of normally expendable tools, equipment, instruments, safety clothing and company uniforms, and the salaries and expenses of personnel engaged in the testing of Powerline Technicians' rubber gloves.[8]

Requirements for tools, equipment and safety clothing would be lower is there was no capital program. The reduction in these requirements would reasonably reflect the reduction in overall work requirements for employees completing construction-related work. Construction-related work is primarily completed by employees working in one of the Company's 3 operating regions. The existing GEC ratio of 48% reflected the percentage of Newfoundland Power's regional labour related to capital work in 1999.

In 2020, approximately 65% of the Company's regional labour related to capital work.[9]

Adjusting the GEC ratio for tools, equipment and safety clothing to 65% is appropriate.

2.4 System Operations

System operations general expenses primarily include labour costs associated with operating the System Control Centre ("SCC").[10]

System operations requirements would be lower if there was no capital program. This is primarily because the SCC would not be required to complete switching orders, protection guarantees, or isolation and grounding requirements associated with capital work.

---

5 Regional employees work in 1 of 3 operating regions: St. John's, Eastern and Western.

6 The 7 positions are: (i) 1 supervisor; (ii) 1 analyst; (iii) 4 engineering technologists; and (iv) 1 area customer representative.

7 Operating supervision general expenses were $4,431,000 in 2020. Applying a GEC ratio of 15% results in a GEC allocation amount of $665,000. Dividing this amount by 7 employees equates to an average labour cost per FTE of $95,000. This figure is comparable to the Company's overall labour cost per FTE of approximately $106,000 in 2020.

8 See Newfoundland Power's System of Accounts dated March 31, 2021, paragraph 7.09, page 34.

9 This percentage is based on the Company's regional labour allocation. It includes 54% in labour charged to capital projects and 11% in labour charged to retirement projects. Labour charged to retirement projects reflects the amount of time associated with removing plant from service.

10 See Newfoundland Power's System of Accounts dated March 31, 2021, paragraphs 7.08 and 7.11, page 34. The account also includes a low amount of non-labour costs ($35,000 in 2020).

Currently, general expenses for system operations are charged directly to GEC.

Newfoundland Power estimates there would be a reduction of 2 FTEs in the SCC if there was no capital program.[11] A reduction of 2 FTEs represents a reduction of 10% in the operating costs for system operations.[12]

Applying a GEC ratio for system operations of 10% is appropriate.

3.0 Non-Construction Activities

3.1 General

There would be lower work requirements performed by the finance, human resources and information systems departments if there was no capital program.

Given the nature of these departments, it is challenging to determine a specific reduction in general expenses for these non-construction activities if there was no capital program. Currently, a nominal rate is applied as a reasonable proxy to determine the portion of general expenses for non-construction activities allocated to GEC.[13]

The Board has suggested the use of a nominal rate of 10% in these circumstances.[14]

Adjusting the GEC ratio for non-construction activities to a nominal rate of 10% is appropriate.

3.2 Finance

Finance general expenses include costs associated with performing accounting functions, including accounts payable, accounts receivable, payroll, cost and plant accounting, general ledger and financial reporting and budgeting.[15]

With no capital program, there would be lower work requirements associated with cost and plant accounting, accounts payable processing and payroll-related tasks. However, a specific reduction in finance general expenses if there was no capital program cannot reasonably be determined.[16]

---

[11] The SCC is required to operate 24 hours a day. Currently, the Company employs 4 teams of 3 Power System Operators at the SCC. If there was no capital program, the Company would reduce its Power System Operators to 4 teams of 2, plus 2 relief workers required for breaks, vacation and unplanned leave. This represents a reduction from 12 to 10 Power System Operators, or 2 FTEs.

[12] System operations general expenses were approximately $2,156,000 in 2020. Applying a GEC ratio of 10% results in a GEC allocation amount of $216,000. Dividing this amount by the Company's overall labour cost per FTE of approximately $106,000 in 2020 equates to 2 FTEs.

[13] Newfoundland Power currently applies a nominal rate of 13% for non-construction activities. This reflects the nominal rate applied at the end of the phase-in period of the incremental cost method in 1999.

[14] See Order No. P.U. 3 (1995-96), page 19.

[15] See Newfoundland Power's System of Accounts dated March 31, 2021, paragraph 7.51, page 38.

[16] A specific reduction in finance general expenses cannot reasonably be determined due to the unique requirements and timelines for each job function. For example, deadlines associated with payroll processing tasks would limit the ability of that same person to also meet deadlines for accounts payable-related tasks. Options to consolidate work requirements in the absence of a capital program are therefore limited.

Applying a nominal rate of 10% for allocating finance general expenses to GEC is appropriate.

3.3 Human Resources

Human resources general expenses include costs of providing services to other departments, such as human resource planning and administration, and activities related to health, safety, training and employee relations.[17] Newfoundland Power proposes to also include employee welfare general expenses in this grouping.[18]

With no capital program, there would be lower work requirements associated with human resources due to the reduction in Company employees that currently complete capital work.[19] However, a specific reduction in human resources general expenses if there was no capital program cannot reasonably be determined.[20]

Applying a nominal rate of 10% for allocating human resources general expenses to GEC is appropriate.

3.4 Information Systems

Information systems general expenses include costs associated with coordinating and developing corporate technology solutions, and providing technical support and training to Company employees. These general expenses also include planning and managing the design, acquisition, programming, testing, operation and maintenance of Company information systems.[21]

With no capital program, there would be lower work requirements associated with planning information systems, including software enhancements and system upgrades. There would also be lower work requirements associated with providing technical support for information systems, as the Company would have fewer employees and fewer personal computers. However, a specific reduction in information systems general expenses if there was no capital program cannot reasonably be determined.[22]

Applying a nominal rate of 10% for allocating information systems general expenses to GEC is appropriate.

---

[17] See Newfoundland Power's System of Accounts dated March 31, 2021, paragraphs 7.75, 7.76 and 7.77, page 41.

[18] Historically, employee welfare expenses were their own category in the GEC calculation. Employee welfare expenses primarily relate to Employee Assistance Programs, the Employee Association and miscellaneous supplies. Employee welfare expenses are part of Miscellaneous Employee Related Costs. See Newfoundland Power's System of Accounts dated March 31, 2021, paragraph 7.78, page 42. While these costs will be lower if there was no capital program, a specific reduction cannot reasonably be determined.

[19] In 2020, there were 611.5 FTEs, of which 214 FTEs can be attributed to completing capital work.

[20] A specific reduction in human resources general expenses cannot reasonably be determined due to the various services and activities of that department. For example, the requirements of certain human resources and safety services would require different jobs based on employees' qualifications to complete the necessary work. Options to consolidate work requirements in the absence of a capital program are therefore limited.

[21] See Newfoundland Power's System of Accounts dated March 31, 2021, paragraphs 7.57 to 7.60, page 39.

[22] A specific reduction in information systems general expenses cannot reasonably be determined due to the ongoing maintenance requirements for the Company's existing information systems.

4.0 Summary

Table 1 summarizes the existing and revised GEC ratios, including actual and *pro forma* GEC amounts based on 2020 costs.

Table 1:
GEC Ratios and Amounts

General Expense	**Existing Ratios**	**2020 Actual ($000s)**	**Revised Ratios**	**2020 *Pro Forma* ($000s)**
Construction Activities				
Capital Planning	Direct	805	Direct	805
Operating Supervision	15%	558	15%	665
Tools, Equipment and Safety Clothing	48%	745	65%	1,009
System Operations	Direct	598	10%	216
Subtotal		**2,706**		**2,695**
Non-Construction Activities				
Finance	13%	243	10%	187
Human Resources	13%	304	10%	252
Information Systems[23]	-	-	10%	317
Employee Welfare[24]	31%	57	-	-
Printing Services[25]	13%	37	-	-
Subtotal		**641**		**756**
Total GEC		**3,347**		**3,451**

Using the revised GEC ratios, the *pro forma* 2020 GEC amount is approximately $3.5 million, which is comprised of approximately $2.7 million in construction-related activities and approximately $0.8 million in non-construction-related activities. These amounts are reasonably consistent with actual 2020 GEC amounts determined using the existing GEC ratios.

23 Information systems general expenses were previously excluded from the GEC calculation. See Appendix A.
24 Employee welfare general expenses are proposed to be grouped with human resources expenses. See section 3.3.
25 Printing services are proposed to be removed from the GEC calculation. See Appendix A.

2023 Revenue Requirement – Income Tax Effects

Pension Cost Allocation
GEC Calculation versus Labour Loading
2023 Revenue Requirement - Income Tax Effects[1]
($000s)

See supporting notes on page 2.

		GEC Allocation	**Labour Loader**
Current Tax Effects			
Additions to taxable income			
Depreciation		57 [2]	57 [3]
Pension expense		4,046 [4]	2,185 [5]
Deductions to taxable income			
GEC		(3,387) [6]	-
Capital cost allowance		-	(143) [7]
Pension funding		(2,699) [8]	(2,699) [8]
Total current tax effects	**A**	(1,983)	(600)
Deferred income tax effects			
Plant Investment [9]			
CCA		-	143
Depreciation (excluding GEC)		-	(57)
Pension Costs [10]			
Funding		2,699	2,699
Expense [11]		(4,046)	(2,185)
Total deferred tax effects	**B**	(1,347)	600
Net income tax effects	**C = A + B**	(3,330) [12]	-
Income taxes @ 30%	**D = C x 30%**	**(999)**	**-**

Supporting notes ($000s)

[1] All amounts relate to 2023 forecast current service pension costs only, as outlined below:

	Total	Capital	Expense
Funded pension plans	4,046	1,861	2,185
RRSP employer contributions (plan is not funded)	3,318	1,526	1,792
Total	**7,364**	**3,387**	**3,977**

[2] Based on allocating GEC to capital projects on a flat rate basis and half year rule.

[3] Any differences in 2023 depreciation expense due to directly charging pension costs to capital projects by way of a labour loader would be immaterial. For illustrative purposes, depreciation expense under the labour loader scenario is equal to depreciation expense calculated under the GEC allocation scenario.

[4] Under the GEC method, pension expense for both financial and income taxes is the total amount. For income tax purposes, pension expense amounts related to the funded pension plans must be added back to calculate taxable income. Only the cash funding amounts associated with these plans are deductible for income tax purposes. As RRSP plans are not funded, the RRSP expense is the same for both financial reporting and income tax purposes. Therefore no additons or deductions to taxable income are required related to the RRSP expense amount of $1,792.

[5] Under the labour loader method, the pension expense addition to taxable income would equal the pension expense related to the funded pension plans. The capital amounts would be directly charged to capital projects rather than being indirectly allocated to capital through GEC.

[6] GEC would be calculated by multiplying the total current service pension costs of $7,364 by 46% to equal $3,387. GEC is deductible for income tax purposes.

[7] The capital portion of RRSP employer contributions are deductible though CCA for income tax purposes.

[8] Funding amounts associated with the Company's funded pension plans are deductible for income tax purposes.

[9] In Order Nos. P.U. 20 (1978), P.U. 21 (1980) and P.U. 17 (1987), the Board approved the Company’s use of tax accrual accounting to recognize deferred income tax liabilities associated with plant investment.

[10] In Order No. P.U. 32 (2007), the Board approved the use of tax accrual accounting to recognize deferred income taxes related to timing differences between pension funding and pension expense.

[11] Under the labour loader method, pension expense in the deferred tax calculation would reflect pension expense for financial reporting purposes (i.e. rather than total pension costs under the GEC method).

[12] The net income tax effect reflects the GEC deduction of $3,387 less the depreciation add back of $57. [3,387 - 57 = 3,330].

Revenue Requirement Timing Differences - Income Tax Effects

Pension Cost Allocation
GEC Calculation versus Labour Loading
Revenue Requirement Timing Differences - Income Tax Effects
($000s)

		Labour Loader A	GEC Allocation B	Difference C = A - B	Annual increase (decrease) in income taxes D = C x 30%
Initial Year	GEC deduction	-	(3,387)	3,387	1,016
Initial Year	Depreciation add back	-	57	(57)	(17)
Initial Year	**Net impact**	**-**	**(3,330)**	**3,330**	**999**
Year 2	Depreciation add back	-	115	(115)	(34)
Year 3	…	-	115	(115)	(34)
Year 4	…	-	115	(115)	(34)
Year 5	…	-	115	(115)	(34)
Year 6	…	-	115	(115)	(34)
Year 7	…	-	115	(115)	(34)
Year 8	…	-	115	(115)	(34)
Year 9	…	-	115	(115)	(34)
Year 10	…	-	115	(115)	(34)
Year 11	…	-	115	(115)	(34)
Year 12	…	-	115	(115)	(34)
Year 13	…	-	115	(115)	(34)
Year 14	…	-	115	(115)	(34)
Year 15	…	-	115	(115)	(34)
Year 16	…	-	115	(115)	(34)
Year 17	…	-	115	(115)	(34)
Year 18	…	-	115	(115)	(34)
Year 19	…	-	115	(115)	(34)
Year 20	…	-	115	(115)	(34)
Year 21	…	-	115	(115)	(34)
Year 22	…	-	115	(115)	(34)
Year 23	…	-	115	(115)	(34)
Year 24	…	-	115	(115)	(34)
Year 25	…	-	115	(115)	(34)
Year 26	…	-	115	(115)	(34)
Year 27	…	-	115	(115)	(34)
Year 28	…	-	115	(115)	(34)
Year 29	…	-	115	(115)	(34)
Year 30	Depreciation add back	-	115	(115)	(34)
Total of years 2 to 30			**3,330**	**(3,330)**	**(999)**
Difference (initial year, less total of years 2 to 30)		**-**	**-**	**-**	**-**

Review of Capitalization Policies and Guidelines

Review of Capitalization Policies and Guidelines

Newfoundland Power Policies and Practices

August 14, 2020

NEWFOUNDLAND POWER
A FORTIS COMPANY

Table of Contents

1.0 Introduction

1.1 Background

On February 21, 2020, the Board of Commissioners of Public Utilities of Newfoundland and Labrador (the "Board") issued Order No. P.U. 5 (2020) approving Newfoundland Power Inc.'s ("Newfoundland Power" or the "Company") *2020 Capital Budget Application*. In that order, the Board stated it would establish a process to review the capitalization practices of both Newfoundland Power and Newfoundland and Labrador Hydro ("Hydro") (collectively, the "Utilities") to ensure consistency with sound public utility practice and the provision of least-cost service to customers.

On April 30, 2020, the Board requested each utility complete a report for the Board describing its capitalization practices relating to capital asset additions. The report was expected to address:

1. the particular accounting standards being followed by the utility;
2. a discussion of how the capitalization practices and/or guidelines are in accordance with sound public utility practice and provide least-cost service to customers; and
3. any other alternatives that may be available to be used by the utility in the development of capitalization practices.

The Board also requested that the Utilities conduct a jurisdictional scan of capitalization practices used by other utilities across Canada.

This report addresses the Board's requests.

1.2 Accounting Standards and Capitalization Practices

An organization that keeps financial records must employ an accounting standard to provide a consistent basis for its accounting. Accounting standards specify how transactions and other events are to be recognized, measured, presented and disclosed in financial statements. In Canada, accounting standards for all entities outside the public sector are issued by the Canadian Accounting Standards Board (the "AcSB").

Newfoundland Power follows an accounting standard based on United States generally accepted accounting principles ("US GAAP") for financial reporting and regulatory purposes.

Accounting standards, among other things, provide guidance in determining whether a cost should be recognized as an expense in the year in which it is incurred, or categorized as a capital cost and amortized over a longer period of time. Newfoundland Power's capitalization policies and practices conform to the requirements of US GAAP, as well as the Board's orders approving the capitalization of certain general expenses.

2.0 Accounting Standards

2.1 General

Newfoundland Power adopted US GAAP as its accounting standard for financial reporting purposes in 2012. Prior to that time, Newfoundland Power's accounting was based on Canadian GAAP.

The change in Newfoundland Power's accounting standard followed a 2008 decision of the AcSB to replace Canadian GAAP with International Financial Reporting Standards ("IFRS") for publicly accountable enterprises commencing with financial reporting periods beginning on or after January 1, 2011. For Newfoundland Power, uncertainty regarding the treatment of regulatory assets and liabilities under IFRS was a significant concern.[1] Because US GAAP permits recognition of regulatory assets and liabilities for financial reporting purposes, and US GAAP was a sanctioned option for Canadian rate-regulated entities, Newfoundland Power chose to move to that standard instead.[2]

In November 2011, the Company filed an application with the Board seeking approval of its adoption of US GAAP for regulatory purposes. The Board approved Newfoundland Power's use of US GAAP for regulatory purposes in Order No. P.U. 27 (2011).

2.2 Public Utility Practice

By adopting US GAAP for regulatory purposes, Newfoundland Power avoided an increase in administrative burden, and possible confusion related to the use of different accounting standards for financial and regulatory reporting.[3]

In approving Newfoundland Power's use of US GAAP for regulatory purposes, the Board confirmed that it was consistent with sound Canadian public utility practice. The Board further noted that the adoption of US GAAP would permit the Company to better reflect the decision-making of the Board in its financial reporting through recognition of regulatory assets and liabilities in a manner consistent with Canadian GAAP. It would also ensure greater transparency in the regulation of Newfoundland Power by ensuring consistency between the Company's accounting for financial reporting purposes and regulatory purposes.[4]

---

[1] Regulatory assets and liabilities arise as a result of the rate-setting process, and are approved by the Board. As at December 31, 2019, the Company's regulatory assets totaled $364 million, while regulatory liabilities totaled $187 million. The adoption of US GAAP allowed the economic impact of rate-regulated activities to be recognized in the Company's financial statements in a manner that was broadly consistent with Canadian GAAP.

[2] To address the concerns of Canadian rate-regulated users of Canadian GAAP regarding certain aspects of IFRS, Canadian securities regulators provided time-limited exemptions that enabled them to adopt US GAAP as an alternative. Newfoundland Power continues to avail of such an exemption.

[3] Newfoundland Power's Application to Adopt US GAAP for Regulatory Purposes dated November 10, 2011, *Newfoundland Power – Adoption of US GAAP for Regulatory Purposes*, JTBrowne Consulting, November 9, 2011, pages 7-8.

[4] Order No. P.U. 27 (2011), page 3.

Although the International Accounting Standards Board ("IASB") continues work to develop an international accounting standard for rate-regulated enterprises, the outcome and timing of this exercise is uncertain.[5]

Newfoundland Power periodically reviews the accounting practices of other Canadian rate-regulated entities. These reviews have confirmed that US GAAP continues to be the most commonly used standard for investor-owned utilities across Canada.

Appendix A provides the results of Newfoundland Power's review of accounting standards followed by utilities across Canada.[6]

3.0 Capitalization Practices

3.1 General

Capitalization, in the context of this report, refers to the categorization of an asset or expenditure as capital in nature, and the recording of the associated cost accordingly in the financial records of an organization. The costs associated with capital assets of Newfoundland Power, ranging from small tools and individual utility poles to buildings and hydroelectric generating facilities, are typically grouped by asset class on the Company's balance sheet as Property, Plant & Equipment or Intangible Assets.

The determination of whether a cost associated with providing electrical service to customers is an *operating* cost to be recognized in the current financial year, or a *capital* cost that will be amortized and recovered through rates over a longer period, depends on whether the cost provides an enduring benefit. Typically, an asset that provides benefits for a period greater than one year is considered to be a capital asset. If a cost is determined to be capital in nature, it is considered appropriate that recovery of that cost be amortized over a period that corresponds to its service life.[7]

Newfoundland Power's customer rates are approved by the Board under a cost of service form of regulation. The costs of serving customers, including those costs incurred to maintain and operate the electrical system, include both operating and capital costs, and are recovered from customers through rates.[8]

---

5 Newfoundland Power continues to monitor the IASB's progress in developing and mandating a standard within IFRS specific to rate-regulated entities.

6 Of the 17 investor-owned utilities whose accounting practices were reviewed, 13 follow US GAAP. Those 13 utilities are all former users of Canadian GAAP who adopted US GAAP instead of IFRS following the AcSB decision.

7 This is generally consistent with the treatment of costs in unregulated enterprises. In the rate-regulated context, the appropriate timing of recovery of capital costs accords with the fairness principle of intergenerational equity. The principle of intergenerational equity is explained in Section 4.0 of this report.

8 The Board's financial consultant completes a detailed annual financial review of Newfoundland Power. This includes a review of the Company's accounts and financial statements to confirm compliance with Board orders.

Capitalization of costs affects only the timing of recovery. It is not determinative of whether the costs are recoverable from customers. The recovery of costs associated with capital assets over their service life is consistent with US GAAP, and with the regulatory principles of intergenerational equity and rate stability.[9]

3.2 Capitalization Policy

Newfoundland Power maintains a formal capitalization policy that governs the determination of whether a cost or expenditure should be recognized as a capital cost. The Company's capitalization policy provides that all expenditures are considered to be operating expenses unless they meet specific capitalization criteria.

Newfoundland Power's capitalization policy provides that, in order to be considered capital in nature, an expenditure must:

i. provide substantial benefits for a period of more than one year;
ii. extend the useful life of an asset or increase the capacity of an asset or the quality of output efficiency and may reduce operating costs; and
iii. be held for use to conduct business/generate income.

If a cost meets these criteria, it is deemed to have been incurred to provide service to customers for a period of greater than one year.

Newfoundland Power's capitalization policy is in accordance with US GAAP.[10] The essential elements of Newfoundland Power's capitalization policies and practices have not changed as a result of the adoption of US GAAP as the Company's accounting standard in 2012.

A copy of Newfoundland Power's capitalization policy is provided in Appendix B.

3.3 Capital Costs

General

The cost of acquiring an asset includes the cost of bringing the asset "to the condition and location necessary for its intended use."[11] Newfoundland Power's capital costs include costs which are directly charged to capital projects, and costs which are indirectly allocated.

For rate-regulated entities, regulators may approve the capitalization of other costs, including operating costs that can reasonably be attributed to capital expenditures. Certain capitalized overheads, or general expenses, are included in Newfoundland Power's capital costs in

---

9 See Section 4.0 Regulatory Considerations for additional information.

10 Newfoundland Power's financial statements are audited annually by an independent auditor, who provides an opinion confirming that the Company's financial statements are materially in compliance with US GAAP.

11 *US GAAP Accounting Standard Codification ("ASC") 360 Property, Plant, and Equipment* provides that "the historical cost of acquiring an asset includes the costs necessarily incurred to bring it to the condition and location necessary for its intended use."

accordance with longstanding practice and Board orders. These are referred to as General Expenses Capitalized, or GEC.

Directly Charged Capital Costs

The vast majority of capital costs can be directly attributed to a capital asset or capital project. These include direct labour charges, external contractor costs and materials costs. Because such items are documented by direct means, including by means of timesheet entries and vendor invoices, accounting administration associated with them is straightforward and not unduly burdensome. For example, the construction of a line extension to connect a new customer incurs direct costs through the purchase of distribution line poles, conductor, associated hardware and the labour required to construct the extension.

Directly charged capital costs account for approximately 90 per cent of Newfoundland Power's capital expenditures. The remaining 10 per cent consists of indirectly allocated costs and GEC.[12]

Indirectly Allocated Capital Costs

Certain capital costs cannot practically or efficiently be charged directly to individual capital assets or capital projects. For example, the conductor used for the line extension in the previous example would be issued through inventory. Although the conductor itself would be charged directly based on the unit cost, allocating the labour associated with the purchasing, storing and handling of a specific inventory item to the individual capital project would be inefficient and unduly costly. The use of an appropriate charge, or loader, on inventory enables a portion of the overhead cost to be allocated to individual projects in a systematic way that is not administratively burdensome.

For Newfoundland Power, the capital costs indirectly allocated to capital expenditures are:

i. Allowance for Funds Used During Construction ("AFUDC");[13]
ii. Vehicle overhead costs; and
iii. Inventory overhead costs.

AFUDC is the cost of financing construction, which is capitalized as part of the cost of plant and equipment.[14] These costs are capitalized based on the capital costs of individual projects in accordance with detailed guidelines.

Newfoundland Power's AFUDC Guidelines are provided in Appendix C.

---

[12] The response to Request for Information NLH-NP-024 in the Company's *2020 Capital Budget Application* proceeding indicates that, on average, approximately 10% of the Company's capital expenditures are indirect in nature. They include AFUDC, vehicle and inventory overhead costs, and GEC.

[13] Under Canadian GAAP, AFUDC was known as Interest During Construction, or IDC. That is also the term used under IFRS.

[14] ASC 980-835-20 Regulated Operations – Interest.

Vehicle overhead costs are capitalized in accordance with the usage of Company vehicles in connection with capital work. A portion of the cost associated with operating and maintaining the Company's fleet of vehicles is reallocated to capital projects based on how employees' base labour cost is recorded. The allocation is accomplished through a loading rate of 23% applied to individual regional operations employees' base labour charged to capital projects.

Inventory overhead costs are capitalized because the purchasing, storing and handling of inventory is an integral aspect of the provision of material for capital projects. These costs are reallocated to the cost of items issued from inventory, and items purchased directly by purchase order, through a loading rate. Each item is loaded at a rate of 15%, up to a maximum of $1,350.[15]

The indirect allocation of capital costs by equitable methods is consistent with utility industry practice as reflected, for example, in accounting instructions under the Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts.[16]

3.4 General Expenses Capitalized

GEC reflects expenses that would not be incurred in the absence of Newfoundland Power's capital program.

Newfoundland Power's GEC consists of direct charges for employees who are deemed incremental as a result of the capital program and indirect allocations of overheads that are considered incremental as a result of the capital program.[17] The capitalization of such costs recognizes that, but for the Company's capital program, a certain number of employees would not be employed and a certain portion of overhead costs would not be incurred.

In the previously noted example of a new line extension, the costs associated with items such as crew scheduling, timesheet approvals, usage of small tools, and vendor invoice review, approval and payment associated with capital work would be captured through GEC.

Newfoundland Power's GEC methodology, as approved by the Board in 1995, is set out in Appendix D.

The capitalization of general expenses is a generally accepted accounting practice in the electric utility industry.[18] Under US GAAP, rate-regulated entities are permitted to capitalize costs that would otherwise be expensed in the year incurred, where such treatment is approved by the

---

15 Loading rates for vehicle and inventory overheads are reviewed annually to ensure they remain appropriate.

16 FERC Uniform System of Accounts – Electric Plant Instructions, Sections 3 and 4. FERC is an independent agency in the United States that regulates utilities. One of FERC's functions is the administration of accounting and financial reporting regulations for rate-regulated entities.

17 In 2019, GEC totaled $6.2 million, comprised of Direct GEC of $1.3 million, Construction Activities of $1.3 million, Non-Construction Activities of $0.7 million and Pension of $2.9 million. A detailed breakdown is provided in Table D1, Appendix D.

18 For example, FERC Uniform System of Accounts – Electric Plant Instructions, Section 4, provides for the capitalization of all overhead construction costs, such as engineering, supervision and general office salaries and expenses.

utility regulator. In other regulatory jurisdictions, such capitalized expenses may be referred to as Capitalized Overheads.

In 1992, using the full cost method of calculating GEC, Newfoundland Power's total GEC was $11.5 million, or 27% of total gross capital expenditures. In 1995, Newfoundland Power proposed a change in its GEC calculation.[19] In 1995, the Board approved guidelines to determine the annual calculation of GEC using the incremental cost methodology. In the interest of rate stability for customers, the Board ordered that the new GEC method be phased in over the 5-year period from 1995 to 1999.[20]

Since the current GEC methodology was fully implemented, GEC has averaged approximately $3.6 million, or less than 5%, on average, of the Company's annual capital budget.

4.0 Regulatory Considerations

4.1 Intergenerational Equity

Intergenerational equity is a principle of fairness that holds that ratepayers in a given period should pay only the costs necessary to provide them with service in that period. In the context of utility ratemaking, the principle of intergenerational equity requires that the costs of capital assets should be recovered from the customers who will benefit from those assets. According to this principle, it would not be fair to burden current customers with costs associated with providing electricity service in the future.

Capital costs are typically recognized for financial and accounting purposes over a longer period than costs that are considered to be current expenses. For rate-regulated entities, costs that are reasonably attributable to capital assets may be approved for recovery from customers over periods corresponding to the service life of the assets. This ensures that the rates paid by ratepayers in a particular period reasonably reflect the costs necessary to provide service to the ratepayers in that period. This is consistent with the principle of intergenerational equity.[21]

4.2 Sound Public Utility Practice

As noted in Section 3.2 Capitalization Policy, Newfoundland Power's capitalization practices are consistent with the US GAAP accounting standard. Based on prior surveys of the practices of

---

[19] Newfoundland Power had used the full cost method to determine the amount of GEC since 1967. Under the full cost method, any general expense incurred in connection with the capital program may be capitalized. Under the incremental method, only general expenses that are incremental to the utility as a result of the capital program may be capitalized. For example, Newfoundland Power's internal audit function would be necessary, even in the absence of a capital program. Accordingly, no costs associated with internal audit are capitalized under the incremental method. The full cost method would allocate a portion of internal audit costs to capital because the internal audit function does perform work related to the capital program.

[20] Order No. P.U. 3 (1995-1996).

[21] The principle of intergenerational equity is routinely considered by the Board and other utility regulators. See, for example, Order No. P.U. 14 (2015), page 12.

other Canadian utilities, Newfoundland Power's adoption of US GAAP in 2011 was consistent with generally accepted sound public utility practice in Canada.[22]

The recent survey of the capitalization practices of Canadian electric utilities carried out by the Utilities, as directed by the Board, shows that Newfoundland Power's use of US GAAP for financial reporting and regulatory purposes is sound Canadian public utility practice. According to the survey results, US GAAP is commonly used by investor-owned utilities, while most of the Crown utilities surveyed follow IFRS.

The survey also confirms that Newfoundland Power's capitalization practices are broadly consistent with those of other Canadian electric utilities. Of the eleven utilities that responded to the jurisdictional survey, seven employ an approach similar to Newfoundland Power's for the capitalization of overhead costs. The method used to determine the applicable capitalization rates or amounts varied amongst respondents, but the survey confirms that the capitalization of general expenses is standard utility industry practice.

Based on the results of the survey, Newfoundland Power's practice of capitalizing pension in GEC or capitalized overhead is not common among Canadian utilities. Ten of the eleven respondents capitalize pension costs by means of a labour loader. For ease of comparison, the estimated impact of pension on Newfoundland Power's GEC and capitalized labour is normalized in the summary of survey responses provided with this report.

Appendix E provides the results of the survey of Canadian utility capitalization practices, and includes comparative information for Newfoundland Power.

4.3 Alternatives to Current Capitalization Practices

The Board's letter dated April 30, 2020 requested that the Utilities' reports on their accounting standards and capitalization practices address other alternatives that may be available to be used in the development of capitalization policies and guidelines. In Newfoundland Power's view, the alternatives are limited.

Capitalization of costs generally follows guidance and industry standards related to the relevant accounting standards. For Newfoundland Power, its capitalization practices accord with guidance and standards applicable to US GAAP, and are broadly consistent with its historic use of Canadian GAAP.

As noted in Section 2.0 Accounting Standards, Newfoundland Power's adoption of US GAAP was principally based on the permitted recognition of regulatory assets and liabilities for financial reporting purposes. Until there is another available accounting standard in Canada that permits the appropriate recognition of these features of Newfoundland Power's financial circumstances, US GAAP is the only reasonable option.

---

[22] Newfoundland Power's Application to Adopt US GAAP for Regulatory Purposes dated November 10, 2011, *Evidence of Newfoundland Power*, page 3, lines 1 – 11.

The Board's order approving Newfoundland Power's use of US GAAP for regulatory purposes outlined the benefits of that option.[23] Those benefits persist, and would be lost if Newfoundland Power were to adopt, for regulatory purposes, a different standard than it uses for financial reporting purposes.

In Newfoundland Power's view, the use of a consistent accounting standard for financial reporting and regulatory reporting is least-cost for customers. It minimizes accounting and record keeping costs while also being aligned with sound public utility practice.[24] Accordingly, the use of capitalization policies and practices that are consistent with both the US GAAP accounting standard and generally accepted Canadian public utility practice is also consistent with the provision of least-cost electrical service to Newfoundland Power's customers.

5.0 Conclusion

Newfoundland Power's adoption of US GAAP for financial reporting and regulatory purposes in 2011 and 2012 was consistent with sound Canadian public utility practice at that time, and consistent with the provision of least-cost electrical service to the Company's customers.

The Company's capitalization policies and practices comply with US GAAP and relevant orders of the Board. These practices are audited annually by the Company's independent auditor and reviewed by the Board's financial consultant.

The results of the survey of Canadian public utilities carried out at the direction of the Board confirms that the Company's capitalization policies and practices continue to be consistent with sound Canadian public utility practice.

In the absence of an alternative accounting standard that provides for reasonable recognition of Newfoundland Power's significant regulatory assets and liabilities, there does not appear to be any reasonable alternative to the Company's current capitalization policies and practices.

---

[23] See Section 2.2 Sound Public Utility Practice at page 2.
[24] See footnote 3.

Appendix A
Summary of Accounting Standards for Utilities

Table A1 - Summary of Accounting Standards for Utilities

Entity	Ownership	2019 [1]
AltaGas Utilities Inc.	Investor	US GAAP
AltaLink Management Ltd.	Investor	IFRS
ATCO Electric Ltd.	Investor	IFRS
British Columbia Transmission Corporation	Investor	IFRS
Centra Gas Manitoba Inc.	Crown	IFRS
Enbridge Gas Distribution Inc.	Investor	US GAAP
Enbridge Gas New Brunswick	Investor	US GAAP
ENMAX Power Corporation	Crown	IFRS
EPCOR Utilities Inc.	Crown	IFRS
FortisAlberta Inc.	Investor	US GAAP
FortisBC Inc.	Investor	US GAAP
Gaz Métro Limited Partnership	Investor	US GAAP
Gazifère inc.	Investor	US GAAP
Heritage Gas Limited	Investor	US GAAP
Hydro One Networks Inc.	Investor	US GAAP
Hydro-Québec	Crown	US GAAP
Manitoba Hydro	Crown	IFRS
Maritime Electric Company Limited	Investor	ASPE
Newfoundland and Labrador Hydro	Crown	IFRS
Newfoundland Power Inc.	Investor	US GAAP
Nova Scotia Power Inc.	Investor	US GAAP
Pacific Northern Gas Ltd.	Investor	US GAAP
Saskatchewan Power Corporation	Crown	IFRS
SaskEnergy Inc.	Crown	IFRS
Toronto Hydro	Crown	IFRS
Union Gas Limited	Investor	US GAAP

[1] The accounting standards were identified through a review of December 31, 2019 financial statements, as filed with SEDAR, or by accessing publicly available information through the respective organizations' websites.

Appendix B
Capitalization Policy

NEWFOUNDLAND POWER
A FORTIS COMPANY

CAPITALIZATION POLICY

This Capitalization Policy provides guidelines for the allocation of costs to either Capital, Retirement or Operating Expense. These principles are intended to conform to accounting principles generally accepted in the United States ("US GAAP"), as well as industry best practices.

Newfoundland Power's capital spending policy provides uniformity and consistency throughout the organization for the accounting of assets that are acquired, built, developed, installed, retired, removed or replaced. This policy should be used to complete both the operating and capital budgets.

Capitalization Principles

1. All expenditures are considered Operating Expense until it is proven that they meet the capital criteria.

2. In certain cases, US GAAP will not provide definitive rules that apply to every possible situation. In these cases, prior to approval of the expenditure, the Manager/Director of the department initiating the project should confirm with the Manager, Finance whether the project is capital or operating.

3. Costs include the amount to acquire, construct, develop or better an asset.

4. Capital assets include but are not limited to land, buildings, property, equipment, machinery, poles, wires, fittings, underground cable, furniture and fixtures, tools and instruments, computers, software, motor vehicles, reservoirs, dams and waterways, water wheels and turbines.

5. All capital assets will be shown at historical cost.

6. Capitalization of all costs will be based on effort (including all support functions) associated with the capital work being performed.

7. Staff will direct charge to projects, where possible.

Capital Expenditures are expenditures in excess of $1,000 and that meet all of the following criteria

1. Provide substantial benefits for a period of more than one year.

2. Extend the useful life of an asset or increase the capacity of an asset or the quality of output efficiency and may reduce operating costs.

3. Are held for use to conduct business/generate income.

* Note that there are individual expenditure items less than $1,000 that can be included in a capital project, such as capital inventory items or timesheet entries. These items contribute to the overall cost of the asset being constructed, and in aggregate would be well in excess of the $1,000 capitalization limit described above.

NEWFOUNDLAND POWER
A FORTIS COMPANY

Capital Expenditures include the following costs [1]

internal labour costs directly charged
contract work directly charged
materials & supplies directly charged
overhead recoveries as outlined below
AFUDC (Allowance for Funds Used During Construction)

Additional Guidelines

Cost of Removal and Retirement

1. When an asset is retired from service, the asset account will be credited with the historical cost of the asset being removed.

2. If the asset being retired is a depreciable asset, the historical cost less any net salvage value and/or any insurance recovered will be charged to accumulated depreciation.

3. If any material is salvaged, the net salvage value is the salvage value less any removal costs.

4. Salvage value is, if the material is sold, the selling price, or if the material is retained for use by the Company, the original cost.

5. The labour charged to retirements should reflect the actual time associated with removal of the plant from service. Percentages have been developed for the following projects:

Project	**Percentage of Internal Labour Charged to Retirements**
Reconstruction 3rd Party Distribution Distribution Reliability Initiative Rebuild Distribution Lines Upgrades of Distribution Lines Transmission Line Rebuild	25%
Replacement of Services Meters Replacement of Street Lights	50%

[1] GEC guidance is detailed in the PP&E process narrative.

NEWFOUNDLAND POWER
A FORTIS COMPANY

Staff Training & Development

1. Initial training to operate or maintain a new plant facility (e.g. substation) being constructed may be capitalized as a part of construction costs.

2. General training, once a plant facility is in service, must be treated as an operating expense.

3. Training and other ongoing support costs related to IT software projects must be treated as an operating expense.

Repairs and Improvements

Ordinary Repairs (Normally Operating Expenses)

Recurring or routine costs for parts, labour etc. that do not extend the useful life of the capital asset but are necessary to keep the asset in normal operating condition (preventative maintenance costs/high wear items) are to be expensed.

Extraordinary Repairs (Normally Capital Expenditures)

Large significant expenditures (relative to the total capital cost of the asset) for major repairs that extend the useful life of the capital asset and are not recurring in nature are generally to be capitalized.

Improvements (Normally Capital Expenditures)

Involves the installation of a new part that is a betterment to the old part and will provide benefit in the form of greater output or lower operating costs for many years.

Overhead Recoveries

1. Vehicle costs will be charged to capital through a labor overhead rate.

2. The cost of Stores and the purchasing function is charged to materials cost through a loading rate.

Questions

Should you have any questions pertaining to the above policy, please contact the Director, Finance.

Effective Date

This policy is dated and effective as of March 31, 2017.

Appendix C
AFUDC Guidelines

AFUDC Guidelines

The following guidelines are used to determine whether a project will be charged AFUDC (Allowance for Funds Used During Construction):

- The project has incurred costs for greater than 3 months (AFUDC charges will begin in the fourth month).
- Project costs have to be >$10,000 for all projects except distribution.
- Distribution projects have to have accumulated costs >$50,000 before AFUDC will be charged to the project.
- Capital acquisitions which are immediately added to plant in service do not attract AFUDC (e.g. transformers, meters, vehicles, office equipment, etc.).
- AFUDC should not be charged on capital projects that are being financed by the customer through a CIAC.
- The interest rate used to calculate AFUDC is the rate of return on average rate base. For 2020, this rate is 7.04% as outlined in Order No. P.U. 2 (2019).
- The interest charges cease once a project is placed "in service" and no further costs remain to be recorded on the project.

Appendix D
Summary of GEC Methodology

Summary of GEC Methodology

On August 11, 1995, Newfoundland Power filed an application requesting that the Board approve a change in the basis of the Company's allocation of costs to General Expenses Capitalized ("GEC"). The proposed change was from the full cost method to the incremental cost method of allocation.

The resulting Order No. P.U. 3 (1995-96) sets forth the basis for the methodology approved by the Board. The Order stated that:

> *"Overhead costs will be considered to be incremental costs of capital projects to the extent that they vary with the level of construction as compared to no capital projects whatsoever. Otherwise the overhead costs are expenses of the period in which they are incurred."*[1]

In the Order, the Board further noted that:

> *"The Board had accepted in the past the merits of full costs, however, in light of low sales growth and diminished capital program, full cost appears to be excessive. This does not mean the Board wishes to minimize capitalization, since to do so would burden today's customers with the costs associated with delivering services long into the future."*[2]

The Order stated that this change was to be phased in over the period January 1, 1995 to December 31, 1999.

The GEC methodology was further considered by the Board during the phase-in period. In Order No. P.U. 36 (1998-99), the Board stated that:

> *"In P.U. 3 (1995-96), the Board recognized that the company would have to determine how specific general expense cost ratios may have to be adjusted over the period of the five year phase-in from a full cost basis to an incremental cost basis and, thereafter, any adjustments to the ratios was intended to be at the discretion of NP."*[3]

The Order also stated that:

> *"The Board agrees that there is no reason to revise or modify the accounting methodology regarding GEC and, therefore, concludes that its previous order adequately addresses the situation."* [4]

These general expense cost ratios have been consistently applied by the Company since the conclusion of the phase-in period in 1999.

---

1 Order No. P.U. 3 (1995-96), page 28.
2 Order No. P.U. 3 (1995-96), page 14.
3 Order No. P.U. 36 (1998-99), page 26.
4 Order No. P.U. 36 (1998-99), page 27.

In Newfoundland Power's *2019/2020 General Rate Application*, a change was proposed to update the capitalization percentage from 11% to the current capital labour split of 46%. The change was as a result of Accounting Standards Update 2017-07, which indicated that only the current service cost component and other post-employment benefits expense be eligible for capitalization and it should be capitalized at the overall labour splits. This change was approved in Order No. P.U. 2 (2019).

Within GEC, there are two primary components: Direct and Indirect.

- Direct – These are employees that are deemed incremental as a result of the capital program. These are primarily employees whose focus is on capital planning and standards as it does not relate to a specific asset.
- Indirect – These are allocations that are considered incremental as a result of the capital program. These are comprised of construction activities, non-construction activities and pension.

Table D1 outlines the current general expense cost ratios that have been applied by the Company.

Table D1 – GEC Cost Ratios & Amount

Function	**Allocation**	**2019 Amount ($000's)**
Direct GEC	N/A	$1,290
Construction Activities		
Operating Supervision & Misc.	15.0%	$547
Tools, Equip., Safety Clothing	48.0%	$794
Non-Construction Activities		
Accounting	13.0%	$238
Human Resources & Admin	13.0%	$326
Printing Services	13.0%	$39
Employees' Welfare	31.0%	$77
Pension Plan	46.0%	$2,892
Total GEC		**$6,203**

Appendix E
Survey of Capitalization Practices of Canadian Utilities

Review of Capitalization Policies and Guidelines

Survey of Capitalization Practices of Canadian Utilities

August 14, 2020

1.0 Overview

On February 21, 2020, the Board of Commissioners of Public Utilities of Newfoundland and Labrador (the "Board") issued Order No. P.U. 5 (2020) approving Newfoundland Power Inc.'s ("Newfoundland Power") *2020 Capital Budget Application*. In that order, the Board stated it would establish a process to review the capitalization practices of both Newfoundland Power and Newfoundland and Labrador Hydro ("Hydro") (collectively, the "Utilities") to ensure consistency with sound public utility practice and the provision of least-cost service to customers.

On April 30, 2020, the Board requested each utility complete a report for the Board describing its capitalization practices relating to capital asset additions. The report was expected to address:

1. the particular accounting standards being followed by the utility;
2. a discussion of how the capitalization practices and/or guidelines are in accordance with sound public utility practice and provide least-cost service to customers; and
3. any other alternatives that may be available to be used by the utility in the development of capitalization practices.

The Board also requested that the Utilities conduct a jurisdictional scan of capitalization practices used by other utilities across Canada.

The Utilities, in consultation with Board staff, developed 11 questions to be included as part of the jurisdictional survey. In total, the survey was sent to 18 Canadian utilities. Eleven utilities responded, for a response rate of 61%.

The survey responses are summarized herein, and comparable information for Newfoundland Power is included. The ownership and responses to questions 1 through 3 for Utility 9 have been redacted for anonymity.

Jurisdictional Scan Results

General

1. What is the primary focus of your organization? For example, is your organization primarily Generation, Transmission, Distribution or some combination?
2. What accounting standards does your organization follow (i.e. US GAAP, IFRS, Private Entity GAAP, etc.)?
3. What form of rate regulation is your organization subject to for rate-setting purposes (eg. Cost of service methodology, performance based, etc.)?
4. Does your organization have any capitalization policies that are approved by your regulator which may be an exception to current accounting standards? If yes, please provide details.

	Ownership	Q1	Q2	Q3	Q4
Utility 1	Investor	Generation, Transmission & Distribution	US GAAP	Performance Based	No
Utility 2	Crown	Generation, Transmission & Distribution	IFRS	Cost of Service	No
Utility 3	Investor	Transmission	IFRS (translate to US GAAP)	Cost of Service	AFUDC, ELG, ARO
Utility 4	Investor	Distribution	US GAAP	Performance Based	No
Utility 5	Crown	Generation & Transmission (Some Distribution)	IFRS	Cost of Service	Regulatory Assets
Utility 6	Investor	Distribution (Some Transmission & Generation)	ASPE (translate to US GAAP)	Cost of Service	IAS-16
Utility 7	Crown	Distribution	IFRS	Custom Incentive Rate-Setting	No
Utility 8	Investor	Transmission & Distribution (Some Generation)	ASPE (translate to US GAAP)	Cost of Service	No
Utility 9	[Redacted]	[Redacted]	[Redacted]	[Redacted]	No
Utility 10	Crown	Generation, Transmission & Distribution	IFRS	Cost of Service	No
Utility 11	Investor	Generation, Transmission & Distribution	US GAAP	Cost of Service	Training
Newfoundland Power	Investor	Distribution, Transmission (Some Generation)	US GAAP	Cost of Service	No

Capitalized Overheads

5. Does your organization capitalize overheads as a component of construction costs? If so:
    a. What types of overhead costs do you capitalize (eg. administration, finance labour, parts, interest, training, pension etc.);
    b. Does your organization follow an established methodology such as the Full Cost or Incremental methods, or another methodology relating to capitalized overhead construction costs?
6. How are the capitalized overhead construction costs allocated amongst the various classes of assets in your organization?
7. Expressed as percentage, what were your overhead construction costs in relation to your total capital expenditures in 2019? Has this ratio changed materially (i.e. >3%) in comparison to your average?

	Q5. a	Q5. b	Q6	Q7
Utility 1	Departmental Costs	Full Cost	Based on asset additions	13.8%
Utility 2	Labour, Meals, Travel Related, Vehicles, IDC	Full Cost	Based on project spend	5.1%
Utility 3	Facility, HR, Finance, Head Office	N/A	Based on monthly CAPEX	10.0%
Utility 4	Departmental Costs	Full Cost	Prescribed percentages	9.0%
Utility 5	AFUDC	N/A	Monthly WIP balance	2.5%
Utility 6	No	N/A	N/A	N/A
Utility 7	2/3 direct labour - Supervision, Engineering, and Supply Chain burden rates. 1/3 vehicle and burdens	Burden Rates	Based on time spent	26.0%
Utility 8	Administration, Finance, 90% Stores Inventory Operating costs, AFUDC	Full Cost	Based on annual CAPEX	1.6%
Utility 9	All directly attributable to projects. Overhead departments charged to O&M	Incremental	Directly charged	N/A
Utility 10	Salaries & benefits, Administrative where directly attributable, Cost of Energy	Incremental	Prescribed percentages	10.0%
Utility 11	Administration, Labour, Office Supplies, Contracts, Rent, Membership due, materials and proportionate amount of current-service pension cost.	Full Cost	Based on project spend	12.0%
Newfoundland Power	Construction and Non-Construction Activities, Pension, AFUDC, Inventory, Vehicle	Incremental	Proportionately based on asset additions.	11.7%[1]

[1] If the capitalized overhead was adjusted to remove the impact of pension, the percentage of capitalized overhead for 2019 decreases to 9.0%. Capitalized overhead for Newfoundland Power includes GEC, AFUDC, and vehicle and inventory overheads.

Capitalized Internal Labour

8. Does your organization have a loading applied to base salaries for capital asset additions? If so:
   a. What is included in the labour loader (i.e. benefits, vacation, pension, etc.)?
   b. How is it allocated to capital assets (through an hourly charge or some other method)?
9. What percentage of your total internal labour costs (regular and overtime, excluding overheads from question #6) were capitalized in 2019 (i.e. total capitalized internal labour divided by total labour costs)? Has this ratio changed materially (i.e. >3%) in comparison to your average?
10. What percentage of your total labour costs (contract labour, regular and overtime, excluding overheads from question #6) were capitalized in 2019 (i.e. total capitalized internal labour divided by total labour costs)? Has this ratio changed materially (i.e. >3%) in comparison to your average?
11. Does your organization have any other method of allocating labour costs to capital assets; for example, loading labour costs on inventory and/or meter replacement? If so, please provide details below.

	Q8. a	Q8. b	Q9	Q10	Q11
Utility 1	Health Benefits, Leave, Incentives, Pension	Time Entry	50.2%	50.2%	Inventory
Utility 2	Allowances, Absences, Payroll Benefits, Severance, Vehicle	Time Entry	16.3%	13.5%	No
Utility 3	Benefits, Pension	Time Entry	58.0%	58.0%	No
Utility 4	Pension, Medical & Dental, CPP, EI	Time Entry	31.1%	14.0%	Inventory
Utility 5	Benefits, Leave, Pension	Time Entry	17.0%	N/A	No
Utility 6	Vacation, Benefits, Pension, Professional Dues, Education, Protective Equipment, Vehicle	Time Entry	35.0%	N/A	No
Utility 7	Pension, CPP, EI, Health & Dental, Safety Uniforms, Tools, Vacation	Time Entry	36.0%	27.0%	No
Utility 8	Benefits, Vacation, Pension	Time Entry	37.0%	46.0%	No
Utility 9	Allowances and Burden (such as Pension and Dental)	Time Entry	14.0%	N/A	No
Utility 10	Benefits (Health, insurance, dental, life, CPP, EI Workers' Comp., Pension)	Time Entry	22.4%	71.9%	No
Utility 11	Employer payroll costs, benefits (health, dental, life & ADD) and DC/DB Pension	Time Entry	25.0%	N/A	No
Newfoundland Power	Health Benefits, Payroll, Vacation, Leave	Time Entry	35.0%[2]	43.0%[3]	Inventory

2 Adjusting Newfoundland Power's capitalized internal labour to account for Pension increases the percentage to 37.5%.

3 Adjusting Newfoundland Power's capitalized total labour to account for Pension increases the percentage to 44.8%.

ELECTRIFICATION, CONSERVATION AND DEMAND MANAGEMENT PLAN

2021-2025

take CHARGE!

BROUGHT TO YOU BY

newfoundland labrador hydro
a nalcor energy company

NEWFOUNDLAND POWER
A FORTIS COMPANY

TABLE OF CONTENTS

1.0 EXECUTIVE SUMMARY

The *Electrification, Conservation and Demand Management Plan: 2021-2025* (the "2021 Plan") is the fourth consecutive plan implemented by Newfoundland Power and Newfoundland and Labrador Hydro under the takeCHARGE partnership. The 2021 Plan introduces customer electrification programs and continues long-standing conservation and demand management ("CDM") programs.

Programs included in the 2021 Plan are designed to be cost-effective and responsive to customer expectations. All programs are based on local market research, stakeholder consultations and estimates of long-term energy and demand impacts.

In 2020, the Newfoundland and Labrador Board of Commissioners of Public Utilities (the "Board") recommended the utilities develop a plan for appropriate electrification and CDM programming. The 2021 Plan is consistent with the Board's recommendation.

The cost of implementing the 2021 Plan is forecast to total $73.1 million over the period 2021 to 2025.

Electrification programs are forecast to increase energy usage by 47.1 GWh over the duration of the 2021 Plan. As customers' energy usage increases, the cost of providing service is spread over more kWh. Over the long term, electrification programs are forecast to provide a rate mitigating benefit of 0.5¢/kWh by 2034.

CDM programs are essential to realizing the rate mitigating benefits of electrification. As customers' energy usage increases, it is necessary to manage system peak in order to manage system costs. CDM programs reduce system peak.

Over the duration of the 2021 Plan, CDM programs are forecast to provide energy savings of 1,610 GWh and 82 MW in peak demand reduction. Combined, these energy savings and peak demand reductions are forecast to lower system costs by approximately $113 million.

Both electrification and CDM programs are forecast to result in lower customer costs. Electrification programs will provide savings for participating customers of approximately $27 million, primarily through vehicle fuel savings. CDM programs will provide electricity bill savings for participating customers of approximately $203 million.

The 2021 Plan is consistent with sound public utility practice and is designed to be flexible to respond to shifts in customer expectations, market trends and access to government funding.

2.0 BACKGROUND

2.1 Customer Program Delivery

Newfoundland Power and Newfoundland and Labrador Hydro ("Hydro" and, collectively, the "Utilities") have offered customer programming under takeCHARGE since 2009. The Utilities have successfully implemented three multi-year plans as part of the takeCHARGE partnership.

All programs implemented since 2009 have been responsive to customers' expectations and consistent with the provision of least-cost, reliable service. Over 60,000 customers have participated in programs since 2009. These customers have saved approximately $131 million on their electricity bills. System costs have been reduced by $142 million since 2009 as a result of these programs.

The most recent five-year plan covered the period 2016 to 2020 (the "2016 Plan"). The 2016 Plan is forecast to exceed target energy savings. Cumulative energy savings are forecast to be 985.8 GWh, compared to a target of 883.2 GWh.

These results have been achieved by strategically removing barriers to energy efficiency in Newfoundland and Labrador. Incentives have addressed customer cost barriers. Education initiatives have addressed gaps in customer awareness and knowledge. By addressing barriers, the Utilities have enabled market transformation for products such as windows to higher efficiency standards.

The 2021 Plan is consistent with the Utilities' long-term history of delivering customer programs.

Schedule A provides a summary of the results and customer benefits delivered from the 2016 Plan.

2.2 Rate Mitigation

Electrification is the process of converting customer end uses from fossil fuels to electricity. Generally, increased sales from electrification provide rate mitigating benefits by spreading the cost of providing service over more kWh.

In the Newfoundland and Labrador context, electrification also provides rate mitigating benefits by maximizing the value of surplus electricity.[1] The provincial retail electricity rate is forecast to exceed the value of export sales over the long term. For example, based on a residential retail rate of 13.5¢/kWh and an export sales value of 4.2¢/kWh, each additional kWh consumed domestically will provide a benefit of 9.3¢.[2]

The rate mitigating value of electrification was confirmed by the Board in the Government of Newfoundland and Labrador reference on rate mitigation options and impacts. In its final report issued in February 2020, the Board stated:

> *Appropriate electrification programs should be pursued by Government and the utilities, taking into account the impact such programs can have on the Island Interconnected system peak through CDM programs. The work being undertaken by Hydro and Newfoundland Power on the potential in the Province for electrification and CDM is critical and this analysis should be completed and made available to the Board and stakeholders as soon as possible.*[3]

The Board encouraged the Utilities and Government to work together on the development of the most appropriate electrification and CDM programs for the province.[4]

The 2021 Plan provides the framework to achieve the rate mitigating benefits described in the Board's final report.[5]

2.3 Current Utility Practice

Electrification is a relatively new trend for North American utilities. However, electrification programs are increasingly part of utility customer energy program portfolios.

Electrification initiatives throughout North America are the result of various public policy objectives. The primary public policy objective driving electrification of the transportation sector is reducing greenhouse gas ("GHG") emissions. This is consistent with the Provincial and

---

[1] Following commissioning of the Muskrat Falls project, the quantity of electricity generated in the province is forecast to exceed domestic requirements for electricity, resulting in a surplus of approximately 3.5 TWh.

[2] The illustration of the net benefit of electrification does not include utility investments such as distribution system upgrades and supply capacity considerations.

[3] See the Board's final report on *Rate Mitigation Options and Impacts: Muskrat Falls Project*, February 7, 2020, page 63.

[4] See the Board's final report on *Rate Mitigation Options and Impacts: Muskrat Falls Project*, February 7, 2020, page 63.

[5] See the Board's final report on *Rate Mitigation Options and Impacts: Muskrat Falls Project*, February 7, 2020, page 109.

Federal governments' policy objectives for transportation electrification.[6] Utility electrification programs typically work in coordination with government initiatives, such as vehicle incentives.

While public policy objectives differ, a number of commonalities exist in North America. The Utilities researched 43 jurisdictions where utilities offer customer electrification programs. Of these 43 jurisdictions: (i) 32 jurisdictions provide incentives for vehicles or chargers; (ii) 31 jurisdictions invest in charging infrastructure; (iii) 27 jurisdictions provide custom solutions for commercial customers; and (iv) 25 jurisdictions undertake managed charging.

Schedule B provides a review of current North American utility electrification initiatives.

Utility CDM programs continue to be offered to customers throughout North America. Long-standing CDM programs offered throughout North America include energy efficient lighting upgrades, home retrofits and customized commercial supports.[7]

The electrification and CDM programs in the 2021 Plan are consistent with utility offerings in other jurisdictions.

3.0 ELECTRIFICATION & CDM POTENTIAL

All customer programming offered under takeCHARGE since 2009 has been based on comprehensive studies of the market potential of CDM technologies. For the first time, the 2020-2034 Potential Study (the "Study") included the market potential of electrification technologies.

[6] Fully electric vehicles do not produce tailpipe emissions. The Government of Canada considers electrification as key to decarbonizing the transportation sector and transitioning to a low-carbon future. Additionally, the transportation sector in Newfoundland and Labrador represents 32% of provincial GHG emissions (see https://www.turnbackthetide.ca/data.shtml#gge-energy-use). The Government of Newfoundland and Labrador has committed to net-zero emissions by 2050 (see correspondence from Former Premier Ball to Prime Minister Trudeau dated May 25, 2020, regarding the effects of COVID-19 on the economy of Newfoundland and Labrador).

[7] The Utilities confirmed the continuation of CDM programs through a jurisdictional survey conducted in 2019. As examples: (i) Efficiency Nova Scotia, FortisBC, Efficiency Maine and Efficiency Vermont provide energy-efficient lighting programs; (ii) Efficiency Nova Scotia, FortisBC and Efficiency Maine provide home retrofit programs; and (iii) BC Hydro, FortisBC, Efficiency Nova Scotia, Manitoba Hydro, Efficiency Maine and Efficiency Vermont provide customized commercial supports.

The Study was conducted using Newfoundland and Labrador-specific inputs to assess electrification and CDM potential, as well as corresponding opportunities and challenges.[8] Multiple scenarios were considered for electrification and CDM potential. A baseline scenario was assessed based on no additional utility intervention. Upper and lower scenarios were assessed based on varying levels of utility intervention, such as differing levels of customer incentives and education.

The primary outcomes of the Study were identification of: (i) cost-effective electrification and CDM measures; (ii) general parameters for program development; and (iii) energy savings and electrification potential by sector and end-use.[9]

Overall, the results of the Study position the Utilities to provide programming that is least cost for customers.

The Study can be found in Schedule C.

3.1 Electrification

The Study assessed the potential for transportation electrification and electrification of space and water heating for residential and commercial customers.

3.1.1 Transportation Electrification

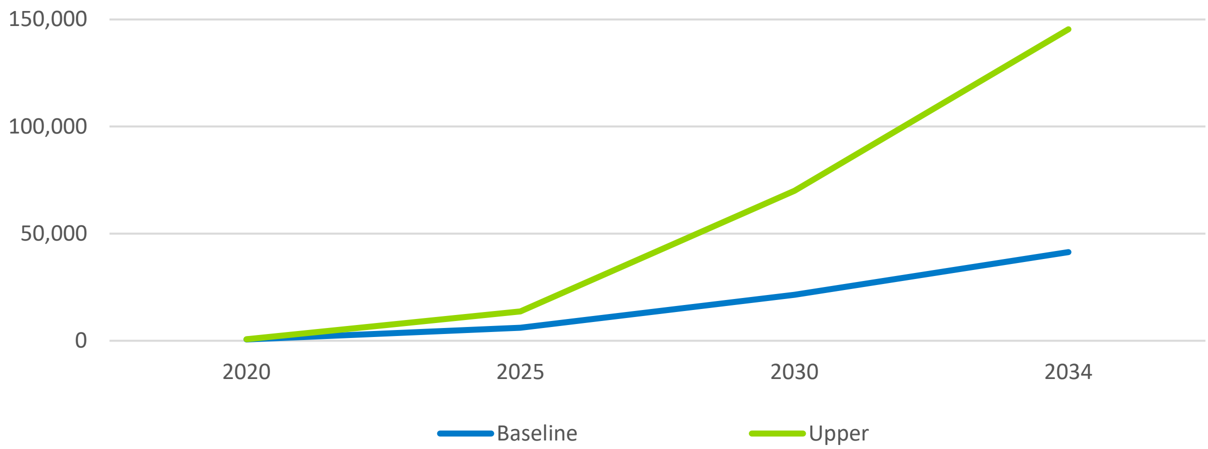
The results of the Study show that there is potential for cost-effective transportation electrification programs.

[8] For example, the fuel switching analysis included an assessment of how many households and businesses can be expected to replace or supplement oil and wood-fired space heating and domestic hot water heating systems with electric heat pump systems under various levels of incentives. The transportation electrification analysis included an assessment of the vehicle market in Newfoundland and Labrador and was divided into the following five categories: personal light-duty vehicles ("LDV"), commercial LDV, medium-duty vehicles, heavy-duty vehicles and buses.

[9] The Study is not intended to give granular information about measures in specific segments, but rather give a macro view of potential. Moreover, it is not a program design document that accurately forecasts energy savings and usage achieved through Utility programs in a given future year, but rather quantifies the total *potential* opportunities that exist under specific parameters.

Figure 1 shows the baseline and upper scenarios for provincial electric vehicle ("EV") adoption forecast for the Study period of 2020 through 2034.

Figure 1
EV Potential
(Total Number of EVs)



The baseline scenario forecasts EV adoption without any additional utility intervention.[10] This scenario forecasts approximately 41,000 EVs on the road by 2034. This level of adoption is forecast to increase retail electricity sales by 266 GWh.

The upper scenario forecasts EV adoption supported by utility investments in charging infrastructure, EV incentives and public education and awareness initiatives. This scenario forecasts approximately 145,000 EVs on the road by 2034. This level of adoption is forecast to increase retail electricity sales by 720 GWh.

EVs represent approximately 40% of annual vehicle sales by 2034 in the upper scenario.[11] This compares to only approximately 10% of annual vehicle sales in the baseline scenario, which is considerably lower than national targets.[12]

The primary difference in EV adoption rates between the baseline and upper scenarios is attributed to variations in access to public charging infrastructure. Under both scenarios,

---

[10] The baseline scenario forecasts adoption based on current levels of investment and support. This includes a commitment by Hydro and the Federal and Provincial Government to increase charging infrastructure (estimated to be the installation of 14 direct-current fast chargers and 14 Level 2 ports in 2020).

[11] Reflects LDV sales, including personal and commercial cars, trucks and SUVs.

[12] The Federal Government has set targets for EVs to reach 10% of LDV sales per year by 2025, 30% by 2030 and 100% by 2040.

direct-current fast charger ("DCFC") deployment has the greatest impact on EV adoption.[13] The Study recommended that DCFC deployment should be prioritized to increase transportation electrification.

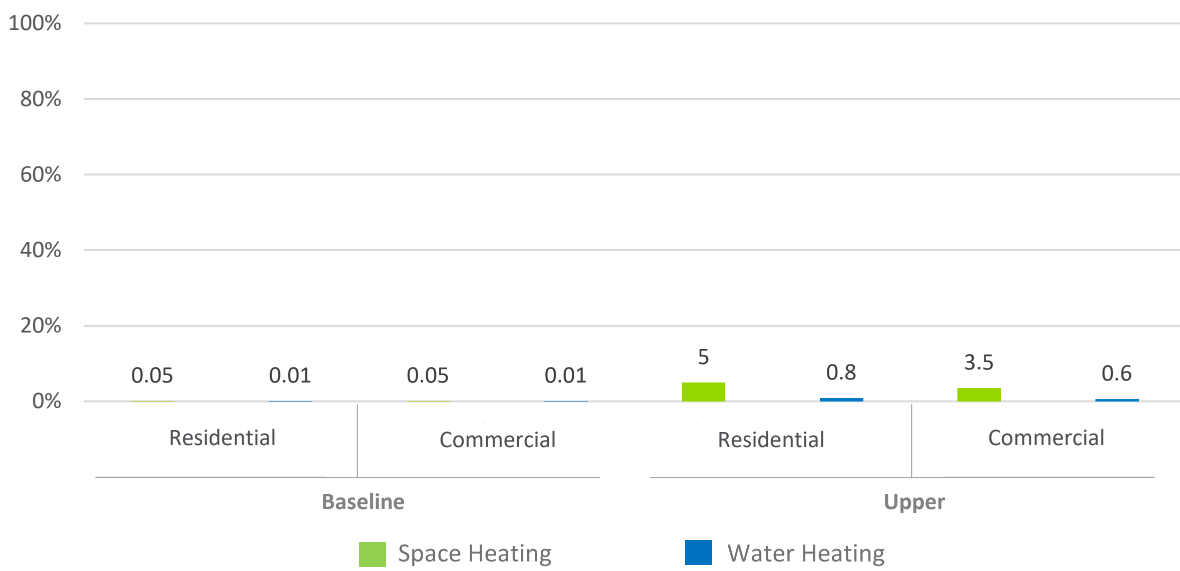
Schedule D provides information on EV technology and global market trends.

3.1.2 Space and Water Heating Electrification

The results of the Study show there is limited potential for electrification of space and water heating in homes and buildings. The limited potential is due to unfavorable customer economics.[14]

Figure 2 shows the Study's baseline and upper achievable scenarios estimated for electrification of space and water heating.[15]

Figure 2
Customers with Non-Electric Space and Water Heating Switching to Electric Heat Pump Systems (%)



13 DCFCs, commonly referred to as Level 3 or fast chargers, charge an EV in approximately 30 minutes to one hour. Level 2 chargers charge an EV in approximately 9 hours. Level 1 chargers charge an EV in approximately 50 hours.

14 In most instances, the capital cost of switching from oil or wood space and water heating systems to an electric system outweighs the monetary benefits of the energy savings. See the Study, Volume 1, page 94, "DMSHP measures did not pass TRC cost effectiveness screening."

15 The baseline scenario forecasts adoption based on current levels of investment and support. The upper potential is defined as the portion of electrification potential that is achievable through utility interventions and programs given institutional, economic and market barriers. For example, increasing incentive levels and enabling activities such as financing and education.

The baseline scenario forecasts no material electrification of space or water heating.[16] This scenario includes no utility intervention. Only a small number of customers are forecast to adopt heat pumps to electrify their space or water heating in this scenario.

The upper scenario forecasts minimal electrification of space and water heating, with an increase in retail electricity sales of approximately 80 GWh. This scenario includes a large financial incentive for non-electrically heated residential and commercial customers. Approximately 5% of residential customers and 3.5% of commercial floor space adopt some form of heat pump system for space heating. With a large financial incentive the adoption of domestic heat pump water heaters is less than 1% for both residential and commercial customers.

3.2 Conservation and Demand Management

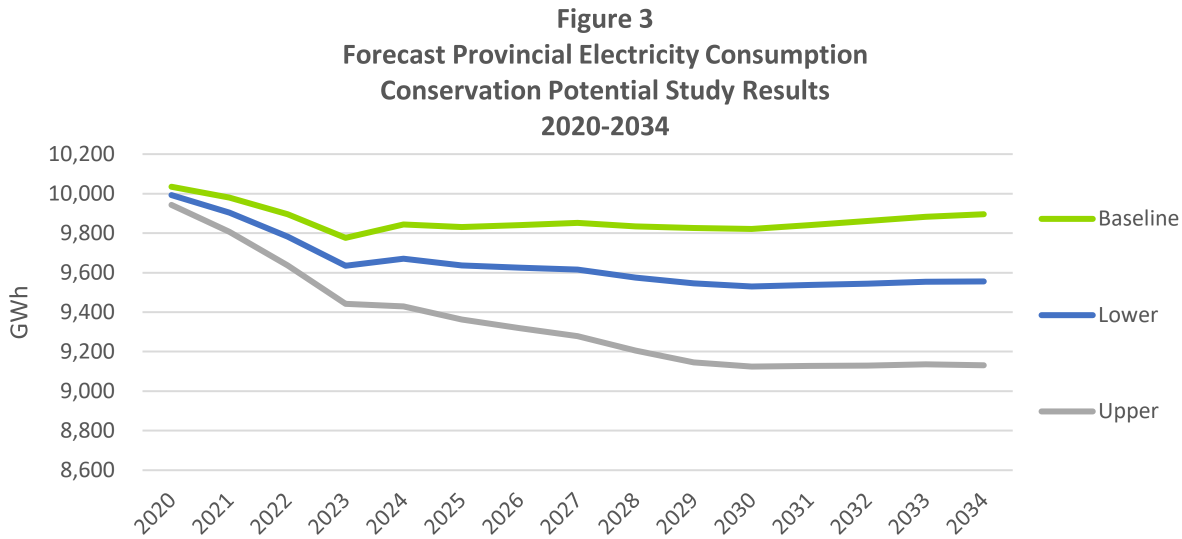
The Study estimated the amount of energy and demand savings that could be achieved through CDM programs. It also considered programs that specifically attempt to reduce consumption at times of system peak.

3.2.1 Energy Conservation Potential

The results of the Study show there continues to be potential for cost-effective CDM programs.

[16] This analysis considered potential for fuel switching to electricity amongst customers using oil or wood for space heating and oil for water heating.

Figure 3 shows the baseline provincial energy usage forecast and the lower and upper achievable energy saving potentials estimated by the Study.[17]



The province's total potential for energy savings by 2034 is forecast to be 764 GWh in the upper scenario and 340 GWh in the lower scenario.[18] In the short term, energy saving potential is similar across all sectors.[19] Due to the high penetration of electrically heated homes, measures that target space heating such as insulation continue to offer potential in the residential sector, along with Home Energy Reports and smaller upgrades such as lighting. Commercial lighting upgrades represent the largest potential for that sector in the short term. Motor and compressor measures offer the largest energy savings opportunity in the industrial sector.

3.2.2 Demand Reduction Potential

The Study shows that there continues to be potential for demand management in the province, however the existing programs achieve the majority of this potential.

---

17 The baseline represents the Utilities' 2019 provincial energy usage forecast. The achievable potential is the portion of new economic conservation potential from 2020 to 2034 achievable through utility interventions and programs given institutional, economic and market barriers. The lower and upper achievable potential include different incentive levels, investments and other enabling activities such as financing and education.

18 In 2034, the baseline is 9,895 GWh. In the upper scenario, the forecast energy consumption is 9,131 GWh. 9,895 GWh - 9,131 GWh = 764 GWh in the upper scenario. Likewise, in the lower scenario, the forecast energy consumption is 9,555 GWh. 9,895 GWh - 9,555 GWh = 340 GWh.

19 The Study forecasts a decline in energy savings through utility programs after 2024 when new lighting and heat pump standards are expected to come into place.

Figures 4 and 5 show the demand reduction potential in the province from specific demand management measures and demand reductions from programs that target energy conservation.[20]

Figure 4
Lower Scenario
Demand Management Potential
2034 (MW)

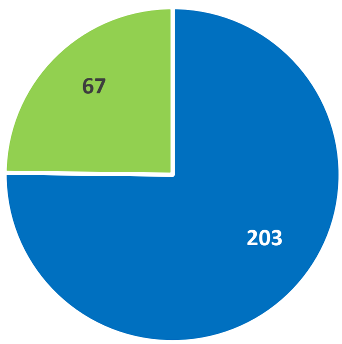
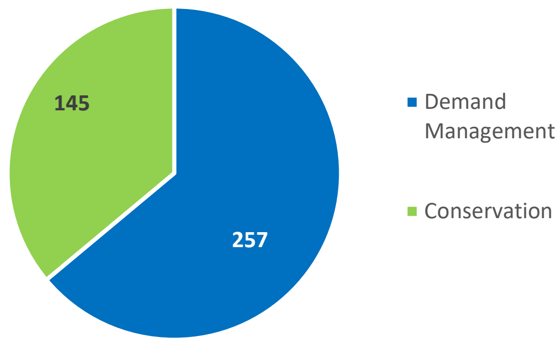


Figure 5
Upper Scenario
Demand Management Potential
2034 (MW)



Demand management potential over the long term is forecast to be achieved through a combination of specific demand management measures and conservation programs.

Figure 4 shows that peak demand reduction of 270 MW could be achieved in the lower scenario.[21] In this scenario, conservation programming accounts for 25% of demand reduction potential and demand management measures account for the remaining 75%.[22] The majority of demand management potential is currently realized through existing industrial and commercial curtailment arrangements.[23]

Figure 5 shows that peak demand reduction of 402 MW could be achieved in the upper scenario by 2034.[24] In this scenario, conservation programming accounts for 36% of demand reduction potential and demand management measures account for the remaining 64%.[25]

---

[20] The achievable potential is defined as the portion of new economic demand and energy efficiency potential that is achievable from 2021 to 2034 through utility interventions and programs given institutional, economic and market barriers. The lower scenario maximizes the impact of current demand response programs. The upper potential scenario introduces additional rate and direct load control demand response measures.

[21] 67 + 203 = 270.

[22] 67/270 = 0.25, or 25%. 203/270 = 0.75, or 75%.

[23] For example, curtailment accounts for 76% of demand management potential in the lower scenario. The remainder consists of dual fuel potential, which involves commercial customers switching to an alternate fuel source at times of peak, and current voltage management practices.

[24] 145 + 257 = 402.

[25] 145/402 = 0.36, or 36%. 257/402 = 0.64, or 64%.

The Study indicated new demand management measures provide little additional benefit to reducing system peak, including Time of Use ("TOU") rates and Critical Peak Pricing ("CPP").[26]

Both TOU rates and CPP require investment in advanced metering infrastructure ("AMI").[27] TOU rates and CPP are not forecast to provide sufficient benefits to justify the cost of AMI until at least 2030, when EV load management may be required to avoid capacity additions. The Utilities will continue to monitor the impacts of EV load to evaluate the benefits of introducing TOU and CPP in the future.

Schedule E provides additional information regarding demand management potential in the province.

3.2.3 Demand Impacts of EV Adoption

Demand management is essential to realizing the full benefits of EV adoption. Unmanaged EV charging which takes place during on-peak hours, could contribute to capacity-related system costs.[28] Managed EV charging shifts charging to off-peak hours which will have the effect of avoiding capacity-related system costs.

---

26 Direct load control (DLC) also offers minimal incremental peak reduction. DLC is forecast to add just 1 MW of savings by 2024, but would include incentive, administration and control infrastructure costs, which offset much of the program benefits.

27 The majority of customers in the province are currently served by automated meter reading ("AMR") technology. AMR allows meters to be read using a radio signal, but is not capable of interval metering for the purpose of implementing time-varying rates.

28 If peak demand is not managed, the Utilities will have to invest in additional generation. High capacity costs, coupled with the coincidence between EV charging and utility load will likely lead to significant increases in peak demand and related system costs if load management is not utilized. December through March is considered the winter peak season and April through November is considered the non-winter off-peak season. Within the winter months, from 7:00 a.m. to 11:00 p.m. on weekdays is considered on-peak. Off-peak hours occur after 11:00 p.m. until 7:00 a.m. and include weekends.

Table 1 shows the net present value ("NPV") impacts of unmanaged versus managed charging of EV load at times of system peak in 2034, as assessed in the Study.

Table 1
EV Demand Management
Benefits and Costs of Unmanaged versus Managed EV Charging[29]
2034

	Unmanaged Charging				Managed Charging			
	MW	Benefits	Costs	NPV	MW	Benefits	Costs	NPV
Baseline	106	$119M	($163M)	($44M)	16	$119M	($52M)	$68M
Upper Scenario	281	$317M	($431M)	($114M)	42	$317M	($147M)	$170M

Unmanaged charging results in a negative NPV of $44 million to $114 million by 2034 due to investments in additional capacity.[30] Managed charging results in a positive NPV of $68 million to $170 million over the same period.

The Study recommends the Utilities pilot managed EV charging to determine the most effective approach at mitigating the impact of EV charging on system peak.

4.0 THE 2021 PLAN

The 2021 Plan introduces programs and education designed to promote electrification of provincial energy use, primarily in transportation. It also continues long-standing CDM programs and education for customers.

29 The benefits include revenue from incremental energy sales. The costs include: (i) supply costs associated with meeting the incremental load growth and (ii) capital costs associated with charging infrastructure investment.

30 If load grows at peak times, additional generation will be required to meet customer needs.

Schedule F provides a description of the programs included in the 2021 Plan.

The 2021 Plan is based on the results of the Study, stakeholder consultation and anticipated future customer economics and system dynamics.

Further details on the stakeholder consultation process can be found in Schedule G.

4.1 Program Screening

All programs in the 2021 Plan are screened to ensure they are cost-effective from a utility and customer perspective.

Cost-effectiveness includes consideration of marginal energy and capacity costs.[31] Marginal energy and capacity costs are forecast to change. Marginal energy costs are forecast to decrease from current levels upon commissioning of the Muskrat Falls project. Marginal capacity costs are forecast to increase due to capacity constraints on the Island Interconnected System. The 2021 Plan is based on the latest estimates of future changes in marginal costs.

Schedule H provides the current forecast marginal cost of energy and capacity for 2021-2040.[32]

Cost effectiveness of CDM programs in the 2021 Plan continues to be evaluated using a Total Resource Cost test ("TRC"). The TRC evaluates programs from the perspective of the customer and the utility.[33] It includes the costs and benefits experienced by the utility system, plus costs and benefits to program participants.

Cost effectiveness of electrification programs in the 2021 Plan is evaluated using a Modified Total Resource Cost test ("mTRC"). The mTRC is substantially the same as the TRC used to

---

31 Marginal cost is the cost to supply electricity to meet the incremental kW of demand and kWh of energy. The provincial marginal cost of energy is based on the export price of electricity and the marginal cost of capacity is based on the avoided cost of adding generation to meet customer requirements at times of system peak.

32 The average hourly marginal cost was provided by Hydro in their 2020 Marginal Cost Update, April 20, 2020.

33 CDM programs also require a positive result for the Program Administrator Cost ("PAC") test as a secondary screening. The PAC evaluates programs from the perspective of the utility. It includes the costs and benefits experienced by the utility system. Research into Canadian and U.S. utility practice shows that the TRC and PAC tests are still appropriate for measuring the benefits of CDM. Use of the TRC and PAC to evaluate customer conservation programs was approved by the Board in Order No. P.U. 18 (2016).

screen CDM programs, but includes non-electrical customer benefits. Specifically, the mTRC recognizes cost savings for customers as a result of lower fuel and maintenance costs. These benefits are essential to the customer economics of electrification technologies.[34]

Schedule I provides further information regarding practices for cost effectiveness testing of electrification programs.

The Utilities also analyzed the rate mitigation value of its electrification programs, pilot projects and infrastructure investment. This analysis identified the customer rate impact of these electrification initiatives.

Section 5.0 provides the rate mitigation results.

4.2 Electrification

The 2021 Plan outlines strategic initiatives takeCHARGE will implement to address customer barriers to electrification. EVs and other technologies are still emerging. Public awareness and understanding of the benefits of EVs are in formative stages. Additionally, current charging infrastructure is insufficient to increase market adoption of EVs.[35] Action is required to remove these barriers and accelerate EV adoption. These actions include investments in charging infrastructure, financial incentives, and awareness and education initiatives.

4.2.1 Utility Charging Infrastructure Investment

The availability of charging infrastructure is forecast to have the highest impact on EV adoption in both the short and long term.[36] Providing sufficient access to charging infrastructure is necessary to eliminate customers concerns about their ability to reach their destinations and support EV adoption.

---

[34] In 2019 Econoler, a third party consultant, performed a jurisdictional scan. The results of this study and supplemental utility research show that not all utilities perform cost effectiveness testing for electrification programs. However, the utilities that do, consider the perspectives of the utility, the customer and society, which is captured in the mTRC.

[35] In a 2019 survey completed by MQO, Newfoundland and Labrador residents ranked access to charging and concerns about reliability of range among the highest barriers to EV ownership.

[36] See the Study, Volume 1, page 105, "*Under both the low and high scenarios, DCFC and L2 deployment have the highest impact on adoption in both the short and long terms. The limited availability of charging infrastructure in the province severely constrains market adoption of LDVs under baseline conditions, and any deployment increases both geographical coverage and availability of charging and has a significant impact on the market*."

Currently, the business case for private investment in DCFC charging stations is weak.[37] This indicates that DCFC deployment in the province will be limited in the absence of utility or government intervention. Through appropriate investment, utility involvement can accelerate electrification of the transportation sector.[38]

The 2021 Plan includes charging infrastructure support through two utility investment models: (i) the make-ready model; and (ii) the utility charging network investment model.

The make-ready model includes the installation of electrical infrastructure to enable customers to purchase and install DCFC. The costs to get a site ready for charger installation are typically a large percentage of the capital required for an installation, at approximately 30% to 40%.[39] This model lowers upfront capital costs which, in turn, improves the business case for commercial customers when installing, owning and operating EV charging stations.[40]

The utility charging network investment model includes the installation, operation and maintenance of charging infrastructure directly by the Utilities. Through utility investment in all aspects of DCFC deployment, this model fully mitigates challenges related to the weak business case for private investment in DCFC.

Combined, these investment models will accelerate the availability of DCFC in the province. This is necessary to maximize the potential for transportation electrification, as outlined in the Study. Under both models, utility involvement will ensure the distribution system is adequately designed and constructed to meet required standards. Utility involvement in DCFC site selection will also work to keep investment costs low.[41]

Both investment models are commonplace in North American jurisdictions that are pursuing electrification of the transportation sector.

---

37 Given the large investment required to install DCFC and low number of EVs in the province, it would be difficult for a private charger operator to make a profit in the near term. Third party charging investment and operation will become more feasible as EV uptake increases. Also see the Study, Volume 1, page 116.

38 MJ Bradley & Associates, *Accelerating the Electric Vehicle Market: Potential Roles of Electric Utilities in the Northeast and Mid-Atlantic States*, March 2017, p.11-12.

39 Chris Nelder and Emily Rogers, *Reducing EV Charging Infrastructure Costs*, Rocky Mountain Institute, 2019, p. 23.

40 Under this model, utilities invest in the site's required electrical distribution infrastructure upgrades up to, but not including, the charging infrastructure, thereby making the site ready for charger installation. The Utilities' infrastructure investments typically include transformer and service capacity upgrades, wiring, conduit, metering upgrades and trenching. The customer oversees the procurement, installation, ownership, maintenance and operation of the chargers.

41 Utility deployment of charging infrastructure will lead to benefits from optimizing station placement within the distribution system to avoid infrastructure upgrades. See the Study, Volume 1, page 111.

Schedule J provides additional information on current utility practice for charging infrastructure investment.

4.2.2 Residential EV & Charging Infrastructure Program

While EVs have lower operating and maintenance costs, they also have a higher upfront purchase cost.[42] The average incremental cost of purchasing an EV compared to a gasoline-powered vehicle is approximately $19,000. EV owners can also incur further costs for the installation of Level 2 charging equipment to ensure timely vehicle charging. This can include the cost of the charger, as well as the cost of upgrading home wiring and electrical capacity.

The Study showed that vehicle purchase incentives can improve the customer business case for EVs. This is forecast to increase the adoption of EVs which, in turn, is forecast to increase EV system load by 16% to 32% by 2025.[43]

The 2021 Plan includes vehicle purchase incentives to address the upfront capital cost of purchasing an EV. The program will work in conjunction with existing Federal rebates to further reduce the capital cost of an EV.[44]

The Study showed managed EV charging will be critical to address the impact of EVs on system peak.[45] Addressing impacts on system peak is necessary to manage capacity-related system costs.

The 2021 Plan includes incentives to address the upfront cost of installing Level 2 chargers. Only Level 2 chargers that are capable of demand management will qualify for these incentives.

---

42 In a 2019 survey completed by MQO, Newfoundland and Labrador residents also ranked cost as one of the highest barriers to EV ownership.

43 See the Study, Volume 1, page 105, *"Incentives can potentially increase EV load by 16 to 32% in the short-term through improving the business case of EV adoption and bridging the market to cost parity. Incentives contribute to both an increase in the number of EVs on the road as well as the shift from plug-in hybrid ("PHEVs") to battery electric vehicles ("BEVs") in the market, which corresponds to an increase in EV load."*

44 This assumes the current federal incentive of $5,000 on a BEV and $2,500 on a PHEV which covers a portion of this incremental cost remains in place for the duration of the 2021 Plan.

45 See the Study, Volume 1, page 150.

4.2.3 Commercial EV & Charging Infrastructure Program

This program provides an incentive to commercial customers looking to replace existing gasoline-powered vehicles with EVs or add an EV to their fleet. As with residential vehicles, there is a higher upfront cost to purchase EVs for commercial use. This program will work in conjunction with the Federal rebate to further reduce the capital cost of an EV.

This program also offers a rebate for eligible purchase and installation costs for installing a Level 2 charger for workplaces and fleets. Installation costs are highly location-specific and typically require some form of electrical extensions, capacity upgrades and trenching. Eligible chargers will be network enabled, allowing for future commercial demand management initiatives.

4.2.4 Custom Electrification Program

The Custom Electrification Program will offer incentives for commercial customers to replace fossil-fuelled technologies with equivalent electric technologies that are more efficient.[46] Incentives will be provided on an individualized basis for projects that are cost-effective from both the customer and utility perspectives.[47] This is comparable to the customized incentives provided to customers under the current Business Efficiency Program.

The Custom Electrification Program will work in tandem with the existing Business Efficiency Program. The 2021 Plan expands the Business Efficiency Program to include an increased focus on demand management. This is necessary to manage impacts on system peak as commercial customers electrify their business processes.

[46] Custom commercial programs allow for the economic evaluation of a specific project considering the energy use and demand impacts of the customer's facility. Evaluation is based on detailed costs and benefits unique to the customer's proposed project.

[47] Examples of individualized projects may include: (i) the installation of ductless mini-split heat pumps ("MSHP") for water or space heating; (ii) the electrification of business processes; (iii) dockside electrification; and (iv) the purchase of electric fork lifts.

Table 2 shows forecast customer energy use estimates by sector for 2021 through 2025 resulting from the electrification programs in the 2021 Plan.

Table 2
Energy Usage Estimates
2021 through 2025
(GWh)

	2021	2022	2023	2024	2025	Total
Residential	0.3	1.5	4.3	9.3	17.1	32.5
Commercial	0.2	0.9	2.0	4.1	7.4	14.6
Total	**0.5**	**2.4**	**6.3**	**13.4**	**24.5**	**47.1**

The electrification programs outlined in the 2021 Plan will result in cumulative customer energy usage of 47.1 GWh. The majority of electrification, 69%, will occur in the residential sector through transportation electrification initiatives.[48]

4.3 CDM Programs

CDM programs continue to provide opportunities to customers in all three sectors: residential, commercial and industrial.

Table 3 shows the portfolio of CDM programs to be offered under the 2021 Plan.

Table 3
Conservation and Demand Management Programs
By Sector

Residential	Commercial	Industrial
Benchmarking HRV Instant Rebates Insulation and Air Sealing Isolated Systems Community Program Low Income Kit Program Thermostat	Business Efficiency Program Isolated Business Efficiency Program Isolated Systems Community Program	Industrial Energy Efficiency Program

All current customer CDM programs will continue in the 2021 Plan, with modifications to certain programs.

[48] 32.5 GWh / 47.1 GWh = 0.69 or 69%

The Instant Rebate program is forecast to end after 2022. At that time, it is expected that regulations[49] may prohibit the manufacturing of certain lower efficiency models of light bulbs, such as halogens.[50] LEDs are expected to become the market standard at that time.

The Insulation program will be expanded to offer incentives for duct insulation and air sealing, helping customers to save further on space heating costs.

A low income program will be introduced providing income-qualified customers with an energy efficiency kit at no cost to the participant.

The Business Efficiency Program demand incentive will be adjusted to better support demand management opportunities in instances where commercial facilities convert space and water heating to electric.

49 Phase two of the Energy Independence and Security Act (EISA) was scheduled to come into effect in the United States ("U.S.") on January 1, 2020, restricting the sale and manufacture of light bulbs that do not meet new minimum energy performance standards for bulb types covered by the regulations. Components of these lighting regulations were delayed by the U.S. Department of Energy. The timing of the implementation of these lighting regulations is uncertain. When implemented, these requirements are anticipated to impact the Canadian market, as the Canadian government has indicated commitments to align efficiency standards with the U.S. The Utilities will monitor changes to these regulations closely.

50 LED light bulbs account for the majority of items rebated through the Instant Rebates program. The Utilities will continue to monitor the saturation of LED bulbs in the marketplace to inform the program end date. Research will be completed through in-store assessments, socket saturation surveys and assessments of free-ridership (an estimate of participants who would have chosen the more efficient product without the program).

Table 4 shows forecast annual customer energy and demand reduction estimates by sector from 2021 through 2025.[51]

Table 4
2021 Plan Annual Energy and Demand Reduction Estimates
2021 through 2025

	2021	2022	2023	2024	2025	Total
Energy (GWh)						
Residential	194.2	212.3	222.9	234.2	246.9	1,110.5
Commercial	53.7	61.0	68.6	76.2	84.7	344.2
Industrial	31.0	31.0	31.0	31.0	31.0	155.0
Total	**278.9**	**304.3**	**322.5**	**341.4**	**362.6**	**1,609.7**
Demand (MW)						
Residential	49.1	53.9	57.5	61.0	65.0	65.0
Commercial	9.8	11.2	12.8	14.5	16.3	16.3
Industrial	0.7	0.7	0.7	0.7	0.7	0.7
Total	**59.6**	**65.8**	**71.0**	**76.2**	**82.0**	**82.0**

The CDM programs in the 2021 Plan are estimated to result in cumulative customer energy savings of approximately 1,610 GWh and achieve peak demand reductions of 82 MW by 2025. The energy savings and demand reduction will occur annually for the life of the installed technologies. The demand reduction will more than offset the increase of 3.2 MW[52] of peak demand resulting from electrification initiatives.[53]

51 CDM program savings indicated throughout the 2021 Plan are cumulative. The savings reflect all technologies installed since program implementation which have not reached the end of their useful life. For example, LED light bulbs are expected to last for seven years. Therefore, LEDs installed in 2019 will provide savings annually until 2025. CDM program savings indicated throughout the 2021 Plan represent *gross* savings achieved by customers. *Net* savings reflect adjustments for: (i) the timing of customer installations giving rise to the energy savings and (ii) program free ridership.

52 The increase in peak demand of 3.2 MW is the result of the additional 47.1 GWh in system load created through electrification initiatives in the 2021 Plan.

53 Demand reduction from the Utilities' curtailment initiatives are reported separately. Results from Newfoundland Power's commercial curtailment program are filed each year with Newfoundland Power's *Curtailable Service Option Report*. Results from Hydro's industrial curtailment program are filed each year with Hydro's *Capacity Assistance Agreement*.

4.4 Customer Education and Research

4.4.1 Customer Education

Over the 2021 Plan period, takeCHARGE will maintain its focus on providing energy saving advice, while expanding its mandate to help inform customer decisions regarding electrification.

Conservation outreach efforts will consider a variety of customer groups, such as those with low income, seniors, renters, students and small businesses. The takeCHARGE website, social media activities and partnerships with industry stakeholders will continue to provide customers with energy efficiency education and support.[54]

Energy efficiency education will focus on helping customers understand and manage their electricity use. Resources will touch on a wide variety of topics, from no-cost ways to save to how to select the most energy efficient technologies for your home or business. takeCHARGE will focus on how to make educational materials more accessible to customers with disabilities, such as vision impairments.

Electrification education will help homeowners and businesses make informed decisions when considering EVs and other fuel switching opportunities.[55] Online resources will outline the benefits and address the barriers to adopting these technologies. EVs will also become a focus of customer outreach activities, including trade shows and employee engagement.

As with past customer conservations efforts, a focus on industry partnerships will be critical in advancing EV adoption. The Utilities will work with key stakeholders, such as automobile dealers, sales staff and current EV owners.[56]

[54] Education will be delivered virtually due to COVID-19 until it is safe to resume in-person outreach. Webinars have been used to deliver a variety of customer presentations for schools, homeowners and trade allies in 2020.

[55] This type of outreach has been successful for utility education initiatives for CDM, helping customers manage their energy use. For example, in 2016, takeCHARGE expanded its educational focus to ductless MSHP. Since its launch, the heat pump website has received approximately 250,000 views.

[56] In 2020, takeCHARGE launched the Go Electric EV drivers club for local EV owners and a website that focuses on EV education.

4.4.2 Customer Research

In advance of the next Study, planned for 2023, the Utilities will undertake a number of research projects regarding electricity end-use trends and the state of the local market for efficient technologies. For example, efficiency standard changes and increased adoption of lighting, mini-split heat pumps ("MSHP"), and EVs are expected to occur in the coming years. It will be important for the Utilities to understand the market dynamics of these changes and other emerging technologies.

The Utilities will also research the costs and customer benefits of a number of technologies through pilot programs, as described below.

Schedule K provides further information on pilot programs for the 2021-2025 period.

Custom Fleet Pilot Program

A significant portion of the forecast electricity consumption in the Study associated with EVs by 2034 is expected to come from commercial vehicles. EVs such as medium-duty vehicles ("MDVs"), heavy-duty vehicles ("HDVs") and buses offer large potential but have unique barriers to adoption, including model availability.[57] Generally, MDVs, HDVs and buses are found to be more sensitive to economics. Electrification of these vehicle classes will therefore require substantial support in the form of incentives or changes in key market economic factors.[58]

The Custom Fleet Pilot Program will allow the Utilities to investigate how to cost effectively overcome the adoption barriers associated with these fleet vehicles. It will also allow the Utilities to investigate opportunities to monitor and manage system peak impacts associated with electrifying large vehicle loads. Implementation of the pilot program will include engaging fleet managers, providing information on fleet electrification opportunities and offering support through technical advice, feasibility studies and financial incentives.

EV Demand Response Pilot Program

By 2034, EV adoption is forecast to increase electricity use. This could potentially change the overall electricity system load shape. The Study indicates that, in the near term, research and

---

[57] Examples of MDVs include delivery vans, box trucks and utility bucket trucks. Examples of HDVs include long-haul and short-haul semi tractors, garbage trucks and dump trucks.

[58] See the Study, Volume 1, page 113. *"Generally, MDV, HDV and buses were found to be more sensitive to economics and will require substantial support in the form of incentives or changes in key market economic factors (electricity rates, fuel prices, etc.) to trigger any significant shift in adoption beyond natural market uptake. Programs targeted towards commercial fleets, awareness campaigns and other initiatives could be potential levers to accelerate the commercial market."*

evaluation should be used to understand these potential impacts and explore mitigation strategies. Managed EV charging will be key to limiting utility system demand impacts. The EV Demand Response Pilot Program will allow the Utilities to assess a number of approaches to control the demand impacts of EVs. Peak demand reduction impacts, cost effectiveness and customer perspectives will be evaluated for each technology, helping to inform the best long-term approach to EV demand management.

The EV Demand Response Pilot Program targets EVs owners who will charge their EV at home using a Level 2 charger. The pilot program will utilize various technologies that help reduce charging at times of system peak such as smart chargers and direct load controllers.

Small Business Direct Install Pilot Program

The Small Business Direct Install Pilot Program will target small business customers, as they are challenged with additional time and financial constraints to making energy efficient upgrades. Energy saving water and lighting measures will be installed at customer facilities. Additionally, the pilot program will help customers identify larger upgrades that can be supported through the Business Efficiency Program, while providing them with other ways to save energy.

The Small Business Direct Install Pilot Program will help inform how these upgrades can be offered to a broad range of customers cost effectively.

Heat Pump Load Research Pilot Program

Due to the increase in adoption of heat pumps and the potential impacts they have on the Utilities' peak load, Newfoundland Power is currently completing load research on MSHPs which is expected to be completed in 2021.[59] The research is being completed over two winter seasons and one summer season and will provide valuable insights into the system impacts of MSHPs, in a time when adoption of this technology is growing.

The Heat Pump Load Research Pilot Program will also provide valuable insights into the demand impacts of ductless MSHPs and how their adoption impacts the energy usage of the whole home.

4.5 Costs and Cost Recovery

Total costs related to customer electrification and CDM initiatives are forecast to be $73.1 million from 2021 through 2025.

59 As of 2019, there were almost 47,000 heat pumps installed in the province. The Study considered the forecast installation of heat pumps. It was forecast that residential MSHP adoption amongst those with electric heat will continue to grow, reaching close to 70,000 installs by 2034.

Table 5 provides of a summary of the Utilities' total electrification and CDM costs from 2021 through 2025.[60]

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

	2021	2022	2023	2024	2025	Total
Utility EV Infrastructure Investment	2,095	2,049	903	1,378	1,306	7,731
Electrification Programs	952	1,762	2,634	3,012	4,145	12,505
CDM Programs	8,211	8,688	7,880	7,834	8,327	40,940
Customer Education and Research[61]	1,466	2,681	3,564	2,932	1,306	11,949
Total	**12,724**	**15,180**	**14,981**	**15,156**	**15,084**	**73,125**

The Utilities anticipate investing $7.7 million in EV charging infrastructure.[62] To maximize the value of investments, existing funding programs will be leveraged to reduce utility costs associated with EV infrastructure deployment.[63]

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

61 Customer education and research includes the costs associated with the heat pump load research pilot program, the small business direct install pilot program, the custom fleet pilot program and the EV demand response pilot program.

62 Utility EV Infrastructure Investment is higher in the first two years reflecting a larger investment in the Utility DCFC Charging Network. Infrastructure costs stabilize in the final three years reflecting continuing investment in Utility DCFC Charging Network and the Make-Ready Charging Infrastructure program. The Utility Charging Network costs do not include any costs associated with Hydro's construction and operation of 14 DCFC and 14 Level 2 chargers throughout the province. This investment was approved by the Board in Order No. P.U. 7 (2020).

63 The Utilities have applied for approximately $1 million in funding to install 19 DCFC's and 19 Level 2 chargers in the province. The Utilities will continue to take advantage of any federal and provincial funding to lower program costs, where possible. Revenues generated from the Utility owned charging infrastructure will also help offset the costs of operating the Utility DCFC Charging Network.

Electrification program costs increase through the period. Customer program participation levels are expected to increase as the adoption of EVs becomes more prevalent.[64]

The Utilities' costs related to CDM programs in the 2021 Plan are forecast to be approximately $40.9 million over the 5-year planning period.[65] This is consistent with the 2016 Plan CDM program costs, which are forecast to be $39.5 million over five years. Forecast changes in program costs primarily reflect costs associated with implementing and evaluating new programs and the conclusion of certain programs or measures through the planning period.

Customer education and research costs are forecast to be approximately $11.9 million over the 2021 Plan period. This includes the expansion of customer education resources, presentations and implementation of four pilots.[66]

Schedule L provides a summary of forecast energy consumption, energy savings and costs for the 2021 Plan.

The Utilities will continue to recover costs associated with CDM programming and major studies over seven years, consistent with the current practice approved by the Board.[67]

To enable the development and implementation of electrification programs in 2021, cost recovery of electrification initiatives and capital must be addressed for 2021.[68] Cost recovery for 2021 will be addressed by the Utilities in applications to the Board. Specifics of long-term amortizations can be determined in the Utilities' next rate cases.[69]

---

64 This reflects increasing customer uptake as the electrification market transforms, driven by the Utilities' investment in EV infrastructure in the province and other enabling activities.

65 Conservation program costs are an average of approximately $8 million annually over the 5-year period.

66 Customer education and research costs are forecast to decline in 2025 to reflect the conclusion of the electrification pilots. Please see Schedule K for further information on the pilot programs in the 2021 Plan.

67 The Utilities have used this approach for customer conservation programs since 2013, based on Order No. P.U. 13 (2013) and Newfoundland and Labrador Hydro – Amended General Rate Application – Parties' Settlement Agreement dated August 14, 2015. The amortization of program costs over a seven-year period remains appropriate because of the extended nature of the electrification and CDM benefits provided by program technologies.

68 Capital investments include costs related to charging infrastructure deployment and information systems enhancements. Supplemental 2021 capital expenditures for the Utilities are estimated to be approximately $2.8 million. The Utilities have applied for approximately $1 million in funding to offset the capital costs required to install 19 DCFC's and 19 Level 2 chargers in the province.

69 The Utilities are examining regulatory approaches in other jurisdictions and their applicability to this jurisdiction.

The Utilities propose to expense annually recurring general electrification and CDM costs, such as education, as they are incurred.[70]

5.0 CUSTOMER BENEFITS

Electrification and CDM provide three principal customer benefits. These customer benefits are outlined in Table 6.

Table 6 Electrification and CDM Customer Benefits		
Benefits	**Electrification**	**CDM**
Customer Rate Mitigation	X	
Lower System Costs		X
Customer Cost Savings[71]	X	X

Electrification provides customer rate mitigation benefits.[72] CDM lowers system costs. Both electrification and CDM lower overall costs to customers. Each of these benefits is described below.

Customer Rate Mitigation

Increased electrification in the province provides rate mitigation benefits to customers over the long term.

---

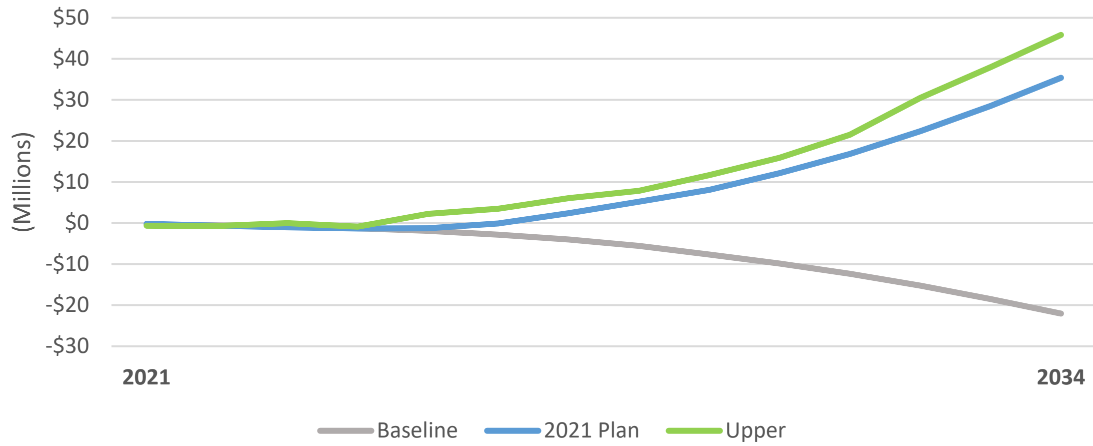
70 While general customer electrification and CDM costs provide benefits to customers in terms of information, know-how and advice, those benefits are not transparently quantifiable in the same manner as program benefits.

71 Participation in electrification and conservation programs can also save customers money in areas other than energy. For example, EV drivers will typically save $1,100 on maintenance over the life of the vehicle compared to a gasoline powered vehicle.

72 In addition to rate mitigating benefits, electrification also benefits customers through reductions in GHG emissions. The electrification initiatives outlined in the 2021 Plan are forecast to reduce GHG emissions by 36,761 megatons of CO^2. Reducing GHG emissions is consistent with federal and provincial policy objectives.

Figure 6 shows the net customer benefits associated with electrification from 2021 to 2034.

Figure 6
Rate Mitigation Benefits from Electrification



In the Study's baseline scenario EV adoption is low.[73] Without any utility intervention system costs will increase. Increased system costs put upward pressure on rates.

The 2021 Plan lays the foundation for increasing electrification over the long term, primarily through EV adoption.[74] Increased electrification is forecast to provide 0.5¢/kWh of rate mitigating benefits by 2034.[75] This is the result of additional net revenue of approximately $127 million over the period 2021 to 2034, or $62 million on a net present value basis.

The 2021 Plan is forecast to achieve approximately 70% of the Study's upper potential in 2034.[76]

---

73 Net revenue represents the total additional revenue available through electrification, less the additional system and program costs. The baseline is the net revenue forecast based on the number of EVs projected with unmanaged charging in the baseline scenario of the Study. The differences in net revenues from Table 1 on page 11 primarily reflects updates to customer rate and marginal cost assumptions since the Study was completed.

74 The 2021 Plan results show the projected outcomes based on the proposed programs and pilots included in the 2021 Plan.

75 The rate mitigating benefit of 0.5¢/kWh is based on a change from the rates approved by the Board in Order No. P.U. 31 (2019) Amended. For example, this additional net revenue translates into an estimated $100 in lower electricity bill charges for an average all-electric residential customer.

76 The upper is the net revenue forecast based on the number of EVs projected in the upper scenario of the Study. The differences in the net revenue from Table 1 on page 11 reflects updates to customer rate and marginal cost assumptions since the Study was completed.

Lower System Costs

CDM programing in the 2021 Plan will decrease system costs by approximately $113 million. This includes system energy and capacity costs.

CDM programs are essential to realizing the customer benefits of electrification. As electrification increases, customers' electricity consumption at times of peak also increases. CDM programming reduces peak electricity consumption. This, in turn, helps manage future investments required to meet increases in system capacity.

Customer Cost Savings

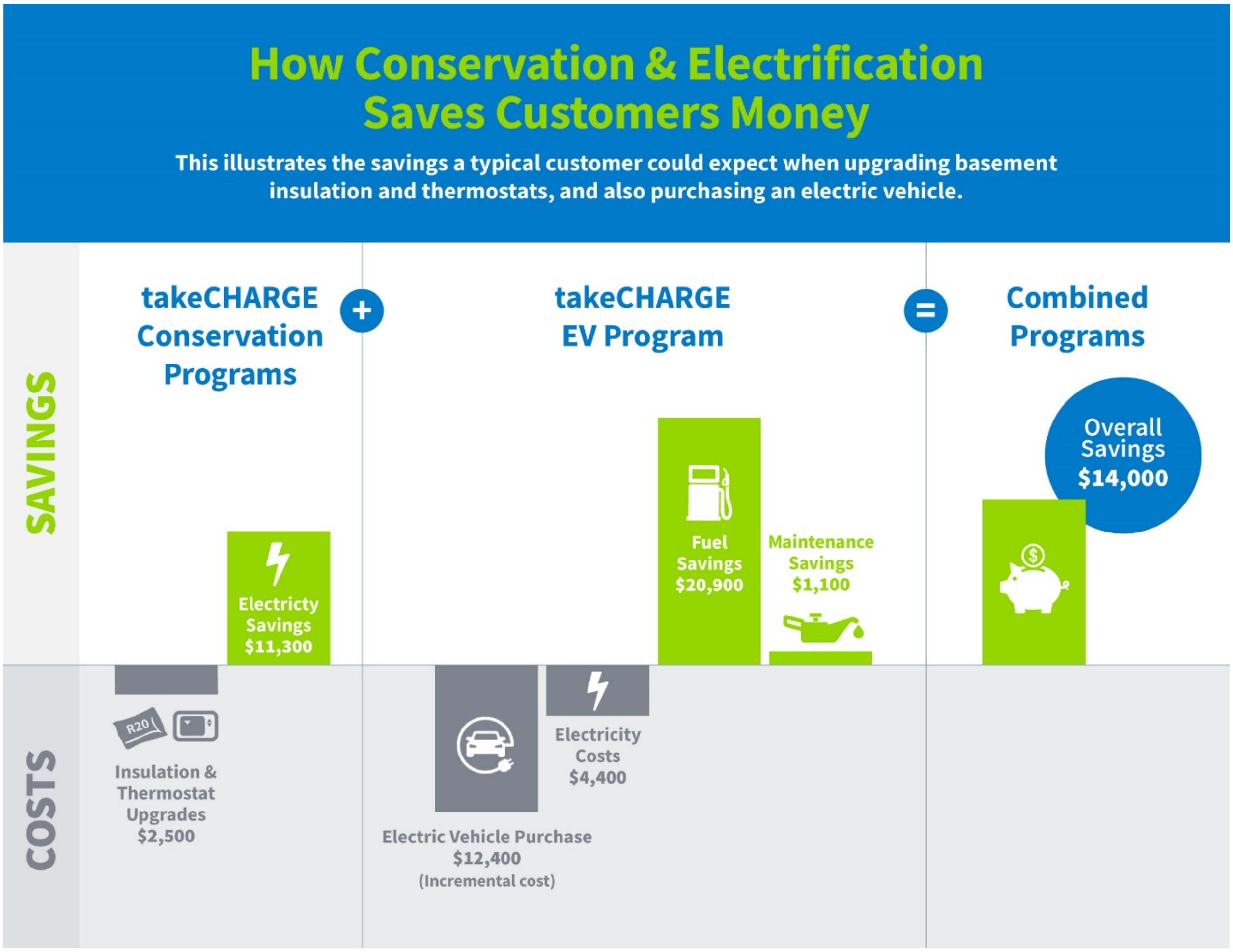
Both electrification and CDM programming will result in cost savings for customers.

Participants in electrification programs will see a reduction in their overall energy costs, primarily through vehicle fuel and maintenance savings. For example, electrification programs will provide fuel savings for customers of approximately $27 million.

Participants in CDM programs will see a reduction in their electricity costs. CDM programs will provide electricity bill savings for customers of approximately $203 million.

Figure 7 provides an illustrative example that demonstrates the cost saving benefits of customer conservation and electrification programs.

Figure 7
Conservation and Electrification Participant Benefits[77]



Following this illustrative example, a customer would incur incremental costs of approximately $19,300 related to conservation upgrades and the purchase of an EV. That same customer would see total cost savings of $33,300 through reduced electricity, fuel and maintenance costs. This results in net cost savings of $14,000.

77 The overall savings of $14,000 represents the total savings of $23,300 ($11,300 in electricity savings + $20,900 in fuel savings + $1,100 in maintenance savings) expected to be incurred over the life of the insulation (25 years), thermostats (11 years) and EV (10 years) minus the total cost of $19,300 to purchase, install and power these technologies ($2,500 to upgrade to programmable thermostats and insulate a basement + $12,400 in incremental costs to purchase an EV + $4,400 in electricity costs for the EV). The costs to upgrade these technologies represent the costs once the rebate has been provided.

Overall, the combination of electrification and CDM programming proposed in the 2021 Plan will result in rate mitigating benefits for customers, lower system costs, and customer cost savings. This shows that, while electrification and conservation can seem like opposing messages, both have the same fundamental objective – to help customers lower their overall costs, including electricity, fuel and vehicle maintenance costs. Communicating these benefits to customers and stakeholders will be important to the success of the 2021 Plan.

6.0 OUTLOOK

The introduction of electrification programming will lay the foundation for market transformation over time. This will provide long-term rate mitigating benefits for customers.

The 2021 Plan will focus on creating the relationships and environment necessary to increase EV adoption in the province. With the established takeCHARGE partnership and growing customer awareness of electrification, the Utilities will continue to seek opportunities to collaborate with complementary organizations and trade allies for customers' benefit. Information sharing and policy coordination with the Provincial Government will also continue.

Schedule M provides letters of support for the 2021 Plan from stakeholders.

The continuation of CDM programming will maintain support for customers in managing their electricity use. These programs and education initiatives will continue to provide bill savings for customers. Outreach will increasingly target specific customer groups, including seniors and customers with low income. Partnerships with trade allies and community groups will be important to broadening customer reach.

The electrification and CDM initiatives in the 2021 Plan are designed to be flexible to ensure continued cost-effectiveness for customers. This requires responding to changing market and system dynamics. For example, EVs are forecast to reach cost parity with gasoline-powered vehicles in 2025. Recent advancements in battery technology may result in cost parity earlier. Annual cost-effectiveness screening will account for such changes to ensure initiatives remain beneficial for customers.

Schedule A
Five-Year Conservation Plan: 2016-2020 Summary

Five-Year Conservation Plan: 2016-2020 Summary

Conservation and Demand Management Programs

Through the delivery of the *Five-Year Conservation Plan: 2016-2020* (the "2016 Plan"), the Utilities jointly offered customer energy conservation programs providing both education and financial incentives to encourage customer installation of energy efficient technologies and adoption of energy efficient behaviours.[1] In addition, Hydro has offered programming for its customers, such as incentives for commercial customers in its isolated system service territories, where market conditions and system costs differ.

Table A-1 shows, by sector, the portfolio of programs that have been offered under the 2016 Plan.[2]

Table A-1
Conservation Programs by Sector

Residential	Commercial	Industrial
Insulation Thermostat Heat Recovery Ventilator Small Technologies[3] Benchmarking Isolated Systems Community Program	Business Efficiency Program Isolated Business Efficiency Program Isolated Systems Community Program	Industrial Energy Efficiency Program

1 Once installed, these energy efficient technologies provide energy savings for the customer throughout the life of the product. For example, a heat recovery ventilator has an estimated life of 15 years and will result in energy saving benefits throughout that period.

2 Detailed program descriptions can be found in Schedule F.

3 This program provided incentives for two different groups of energy efficient products, appliances and electronics, and smaller technologies rebated by retail partners at the point of purchase. The appliances and electronics program was ended on December 31, 2017. The program originally provided rebates on refrigerators, chest freezers, washing machines and televisions. The Instant Rebate component offers rebates on a variety of low-cost energy efficient products. Products include LED lighting, weather stripping, dehumidifiers, dimmer switches, showerheads, smart power strips and more.

Table A-2 provides a summary of energy savings and demand savings forecast to be achieved through the Utilities' conservation programs from 2016 to 2020F. The energy and demand savings build upon the achievements of the conservation programs since 2009.

Table A-2
Summary of 2016 Plan Results[4]
2016 through 2020F

	2016	2017	2018	2019	2020F	Total
Annual Energy Savings (GWh)						
Residential	89.2	114.5	141.2	165.4	178.5	688.8
Commercial	15.0	24.1	31.8	40.2	46.4	157.5
Industrial	25.8	25.8	25.9	31.0	31.0	139.5
Total Energy Savings	**130.0**	**164.4**	**198.9**	**236.6**	**255.9**	**985.8**
Annual Demand Savings (MW)						
Residential	26.2	32.3	37.6	44.1	45.2	45.2
Commercial	4.0	5.0	6.3	7.1	8.4	8.4
Industrial	-	-	-	0.7	0.7	0.7
Total Demand Savings	**30.2**	**37.3**	**43.9**	**51.9**	**54.3**	**54.3**

Delivery of the 2016 Plan is estimated to result in 985.8 GWh of cumulative energy savings, exceeding the target of 883.2 GWh. The residential programs are the largest contributor to energy savings. Commercial energy savings have grown throughout the plan, and are expected to account for approximately 16% of overall energy savings achieved.

The Utilities continuously review customer energy conservation programs to ensure they provide relevant energy conservation initiatives for customers and are responsive to evolving customer needs

[4] CDM program savings indicated for the 2016 Plan are cumulative. The savings reflect all technologies installed since program implementation which have not reached the end of their useful life. For example LED light bulbs are expected to last for seven years. Therefore LEDs installed in 2014 will provide savings annually until 2020. CDM program savings represent gross savings achieved by customers. Net savings reflect adjustments for: (i) the timing of customer installations giving rise to the energy savings and (ii) program free ridership (an estimate of participants who would have chosen the more efficient product without the program).

and expectations.[5] The Utilities also delivered a number of energy efficiency programs for the Provincial and Federal Governments. A description of these programs is outlined in Table A-3.

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) aims to reduce greenhouse gas emissions. In 2019, takeCHARGE extended its Insulation and Thermostat Rebate Programs to customers with oil heat through the LCELF and Provincial Government funding.
Heat Pump Rebate	The Heat Pump Rebate program funded by the Government of Newfoundland and Labrador and administered by Hydro, offered $1,000 rebates to qualified homeowners for mini-split, multi-split and central heat pumps. Rebates were issued to qualified homeowners for heat pumps purchased and installed on or after October 15, 2019 until the program ended on March 15, 2020.
Energy Efficiency Loan Program (EELP)	The Utilities delivered the EELP for the Government of Newfoundland and Labrador from 2017 to 2020. Through EELP, reduced rate financing was provided for insulation, heat pumps and home energy assessments to assist customers with the financial barriers to making their homes more energy efficient.

Education and Support
The Utilities continued to focus on customer education and community outreach in the delivery of the 2016 Plan. Energy conservation education and support was provided through a variety of channels, which include a joint website and social media accounts, outreach activities, school presentations and partnerships with other organizations. Table A-4 shows the number of energy conservation related customer-initiated contacts and outreach events from 2016 to 2020.

[5] Throughout the 2016 Plan, Island Interconnected System residential and commercial programs were reviewed by external third-party evaluators. Programs are evaluated on their energy savings, market impacts and delivery effectiveness. Evaluation findings are used to make necessary adjustments such as energy savings claims and to refine program design and implementation. For example, outcomes of the Instant Rebate evaluations have allowed the Utilities to extend this program beyond its original estimated end date of 2018. Annual market research continued to show significant room for growth in the residential LED market with a study commissioned in 2018 reporting approximately 3.5 million sockets that could be converted to more efficient lighting.

Table A-4 **Customer Contacts and Outreach Events** **2016 through 2020F**						
	2016	**2017**	**2018**	**2019**	**2020F[6]**	**Total**
Customer Inquiries[7]	8,411	10,170	9,019	9,670	5,430	42,700
Website Visits	241,359	302,909	411,045	376,988	392,049	1,724,350
Outreach Events	194	303	313	298	48	1,156

The Utilities are expected to have over 42,000 customer contacts and over 1.7 million visits to the takeCHARGE website from 2016 through 2020. The majority of customers choose electronic means of communication to obtain information on energy conservation and rebate programs. This is consistent with promotion of the takeCHARGE website as the primary resource for customer inquiries and information.[8]

The Utilities participated in an average of 277 community outreach events each year between 2016 and 2019. Through these events, takeCHARGE assisted customers with their energy efficiency questions, while helping them to take advantage of the takeCHARGE rebate programs. Energy conservation presentations were delivered to retailers, students, community groups and associations.[9] takeCHARGE information booths were displayed at trade fairs, industry conferences and retail stores across the province. The Utilities also offered a number of specialized outreach events such as the takeCHARGE of Your Town Challenge, Make the Switch, Energy Efficiency Week, Customer Energy Forums and the Luminary Awards.[10]

Trade allies, retailers and a variety of partners play an integral role in helping customers make knowledgeable decisions regarding energy efficiency. Trade allies and retail partners share and display information about takeCHARGE programs and promote energy efficiency upgrades during special events. The Utilities continued to develop new partnerships and strengthen existing relationships. Some of these organizations include Seniors NL, the Association of Newfoundland and Labrador Realtors, Empower NL, the Canadian Home Builders Association, Municipalities Newfoundland and

6 2020 customer engagement results were impacted by the COVID-19 pandemic.

7 Customer inquiries include calls and emails received by the Utilities regarding energy efficiency.

8 The Utilities continued to build upon existing energy conservation resources for commercial and residential customers. New website resources are helping businesses to better understand how their facilities use electricity and suggest low-cost and no-cost ways to save energy. Online content for residents was evolved with a focus on how homes use electricity, no-cost ways to save, and key topics such as heat pumps.

9 Since 2016, over 13,500 students in over 165 schools throughout the province have received presentations about energy conservation through the takeCHARGE *Kids in Charge* K-I-C Start School Program. The program also includes an annual contest and online resources.

10 Each utility provides an annual grant of $7,500 for energy efficient upgrades to a municipality in their service territory through the takeCHARGE of Your Town Challenge. The Make the Switch LED bulb giveaway provides energy efficient light bulbs to non-profit and community organizations. Each annual Energy Efficiency Week reminds customers that takeCHARGE is here to help customers manage their electricity use, while Customer Forums connect residential and commercial customers with energy experts throughout the year. The takeCHARGE Luminary Awards were launched in 2018, providing an opportunity to recognize the progressive work in energy efficiency achieved by utility partners and customers.

Labrador, Newfoundland and Labrador Housing Corporation, the Government of Newfoundland and Labrador and the Government of Canada.

Costs

Table A-5 provides a summary of the research and customer education and conservation and demand management (CDM) program costs incurred by the Utilities from 2016 through 2020.[11]

Table A-5
Conservation Costs
2016 through 2020F
($000s)

	2016	**2017**	**2018**	**2019**	**2020F**	**Total**
Research and Customer Education	864	1,022	1,008	1,846	1,296	6,036
CDM Programs	8,320	8,300	7,632	7,631	7,597	39,480
Total	**9,184**	**9,322**	**8,640**	**9,477**	**8,893**	**45,516**[12]

The Utilities' costs related to customer energy conservation programs have remained stable during the 2016 Plan. This is primarily a result of consistent program offerings with fluctuations in research costs for initiatives such as commercial and residential end use surveys and the 2020 – 2034 Potential Study (the "Study").[13] The Utilities each bear the costs related to the provision of customer programming in their own service territory. General conservation 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 split on an 85% / 15% basis between Newfoundland Power and Hydro, respectively.[14]

---

11 Newfoundland Power's current conservation cost recovery practice reflects Board Order No. P.U. 13 (2013). Conservation program costs are deferred and amortized over a seven-year period. Through annual operation of the Company's Rate Stabilization Adjustment, customer rates are adjusted to reflect any difference between the conservation program costs included in the most recent test year and the costs actually incurred. Newfoundland Power's annually recurring general conservation costs related to providing general customer information, community outreach and planning are expensed in the year in which the costs are incurred. As of August 14, 2015, associated with a general rate application filed by Hydro on July 30, 2013, and an amended general rate application filed by Hydro on November 10, 2014, it was agreed that "Hydro's proposal to defer and amortize annual customer energy conservation program costs, commencing in 2015, over a discrete seven-year period in a Conservation and Demand Management (CDM) Cost Deferral Account should be approved."

12 The total cost to deliver the 2016 Plan from 2016 through 2020 is forecast to be $45.5 million. The $4.4 million incurred above the plan forecast is primarily due to the extension of the Instant Rebates and Benchmarking programs. The Instant Rebates Program was due to end after 2018, but was continued in 2019 and 2020. The Benchmarking Program was due to end after 2019, but was extended into 2020. Both programs continue to offer cost-effective energy and demand savings.

13 The Study and commercial and residential end use surveys were completed in preparation for the 2021 Plan.

14 This approach to division of jointly incurred costs reflects the proportion of customers served by each utility. The Study is an exception to this split, where Newfoundland Power and Hydro split the costs 60%/40%, respectively.

Tables A-6, A-7 and A-8 outline energy savings, demand savings and costs for each energy conservation program by sector from 2016-2020F

Table A-6
Conservation Programs
Energy Reductions: 2016 – 2020F
by Sector
(GWh)

	2016	2017	2018	2019	2020F	Total
Residential						
Insulation Program	29.2	33.1	37.5	42.9	48.4	191.1
Thermostat Program	11.6	15.7	18.9	22.1	24.3	92.6
ENERGY STAR Window Program	9.9	9.9	9.9	9.9	9.9	49.5
Coupon Program	0.2	0.2	0.2	0.2	0.2	1.0
HRV	0.6	0.8	1.1	1.4	1.5	5.4
Small Technologies	31.2	40.4	52.5	63.1	70.5	257.7
Benchmarking	-	6.8	12.4	16.3	14.0	49.5
Isolated Systems Community Program	6.2	7.3	8.4	9.2	9.4	40.5
Block Heater Timer Program	0.3	0.3	0.3	0.3	0.3	1.5
Total Residential Portfolio	**89.2**	**114.5**	**141.2**	**165.4**	**178.5**	**688.8**
Commercial						
Business Efficiency Program	14.6	23.6	31.1	39.1	44.8	153.2
Isolated Systems Business Efficiency Program	0.4	0.5	0.7	0.7	0.8	3.1
Isolated Systems Community Program (Commercial)	-	-	-	0.4	0.8	1.2
Total Commercial Portfolio	**15.0**	**24.1**	**31.8**	**40.2**	**46.4**	**157.5**
Industrial						
Industrial Energy Efficiency Program	25.8	25.8	25.9	31.0	31.0	139.5
Total Portfolio	**130.0**	**164.4**	**198.9**	**236.6**	**255.9**	**985.8**

Table A-7
Conservation Programs
Program Costs: 2016 – 2020F
by Sector
($000s)

	2016	2017	2018	2019	2020F	Total
Residential						
Insulation Program	881	1,184	1,240	1,578	1,281	6,164
Thermostat Program	446	593	456	496	573	2,564
ENERGY STAR Window Program	-	-	-	-	-	-
Coupon Program	-	-	-	-	-	-
HRV	147	132	219	156	239	893
Small Technologies	4,291	2,291	1,911	1,588	950	11,031
Benchmarking	523	883	836	820	862	3,924
Isolated Systems Community Program	451	936	981	577	992	3,937
Block Heater Timer Program	-	-	-	-	-	-
Total Residential Portfolio	**6,739**	**6,019**	**5,643**	**5,215**	**4,897**	**28,513**
Commercial						
Business Efficiency Program	1,508	2,199	1,870	1,805	2,122	9,504
Isolated Systems Business Efficiency Program	45	41	99	24	192	401
Isolated Systems Community Commercial	-	-	-	412	-	412
Total Commercial Portfolio	**1,553**	**2,240**	**1,969**	**2,241**	**2,314**	**10,317**
Industrial						
Industrial Energy Efficiency Program	28	41	20	175	386	650
Total Portfolio	**8,320**	**8,300**	**7,632**	**7,631**	**7,597**	**39,480**

Table A-8
Conservation Programs
Demand Reductions: 2016 – 2020F
By Sector
(MW)

	2016	2017	2018	2019	2020F	Total
Residential						
Insulation Program	8.8	10.5	12.4	14.6	15.8	15.8
Thermostat Program	3.5	3.7	3.8	3.9	4.0	4.0
ENERGY STAR Window Program	3.1	3.1	3.1	3.1	3.1	3.1
Coupon Program	0.1	0.1	0.1	0.1	0.0	0.0
HRV	0.2	0.2	0.3	0.4	0.4	0.4
Small Technologies	8.6	11.1	13.4	15.8	17.1	17.1
Benchmarking	-	1.2	1.9	3.3	1.7	1.7
Isolated Systems Community Program	1.9	2.2	2.6	2.9	3.1	3.1
Block Heater Timer Program	-	-	-	-	-	-
Total Residential Portfolio	**26.2**	**32.1**	**37.6**	**44.1**	**45.2**	**45.2**
Commercial						
Business Efficiency Program	3.7	4.7	5.9	6.7	7.9	7.9
Isolated Systems Business Efficiency Program	0.3	0.3	0.4	0.4	0.4	0.4
Isolated Systems Community Program (Commercial)	-	-	-	-	0.1	0.1
Total Commercial Portfolio	**4.0**	**5.0**	**6.3**	**7.1**	**8.4**	**8.4**
Industrial						
Industrial Energy Efficiency Program	-	-	-	0.7	0.7	**0.7**
Total Portfolio	**30.2**	**37.1**	**43.9**	**51.9**	**54.3**	**54.3**

Schedule B
North American Electrification Initiatives

Table B-1 shows utility electrification initiatives in North America by State and Province.

Table B-1
North American Electrification Initiatives

	Vehicle Incentive[1]	Commercial EV Charger Incentive[2]	Residential EV Charger Incentive[3]	Make Ready Investment[4]	Utility DCFC Investment[5]	Fleet Support[6]	Custom Commercial Incentive[7]	DCFC Incentive[8]	Managed Charging[9]
Alabama									X
Alaska	X								X
Arizona		X	X		X		X		X
Arkansas			X			X	X		
BC	X[10]		X[10]		X[11]				X
California	X	X	X	X	X	X	X	X	X
Colorado			X	X		X			X
Connecticut	X		X						

1 Vehicle incentives include programs where an incentive is paid to customers to reduce the upfront cost of an EV.
2 Commercial EV charger incentives include programs that provide commercial customers with an incentive towards the purchase of a level 2 charger.
3 Residential EV charger incentives include programs that provide residential customers with an incentive towards the purchase of a level 2 charger.
4 Make ready investment includes initiatives to reduce the cost to install EV charger equipment. These programs would typically include a portion of the rebate or investment towards the costs required to install an EV charger.
5 Utility DCFC investment includes initiatives where the utility owns and operates DCFC infrastructure.
6 Fleet support includes initiatives that are focused on supporting commercial customers in converting their vehicle fleet to electric vehicles.
7 Custom commercial incentives include programs that provide incentives towards converting non-electric vehicle technologies to electric, such as forklifts or heat pumps.
8 DCFC incentives include programs that provide incentives off the purchase price of DCFC infrastructure.
9 Managed charging includes initiatives where the utility has a program to encourage off peak charging of EVs, such as managed charging through smart charging or EV off peak incentive rates.
10 The vehicle incentive program in BC and Quebec is funded by the Provincial Government. The vehicle incentive program in New York is funded by the State.
11 Section 18 of British Columbia's Clean Energy Act states that in setting rates under the Utilities Commission Act for a public utility carrying out a prescribed undertaking, the commission must set rates that allow the public utility to collect sufficient revenue in each fiscal year to enable it to recover its costs incurred with respect to the prescribed undertaking. Order in Council No. 339 amended Greenhouse Gas Reduction (Clean Energy) Regulation. B.C. Reg. 102/2012 to include electric vehicle charging stations as a prescribed undertaking under the Clean Energy Act.

Table B-1
North American Electrification Initiatives

	Vehicle Incentive[1]	Commercial EV Charger Incentive[2]	Residential EV Charger Incentive[3]	Make Ready Investment[4]	Utility DCFC Investment[5]	Fleet Support[6]	Custom Commercial Incentive[7]	DCFC Incentive[8]	Managed Charging[9]
District of Columbia				X		X			X
Florida	X				X[12]		X		
Georgia		X	X	X	X				X
Hawaii				X	X	X			X
Illinois							X		X
Indiana					X				X
Iowa		X	X				X		
Kentucky[13]			X		X	X			X
Louisiana							X		
Maine	X								
Maryland		X	X	X	X	X			X
Massachusetts				X	X	X			X
Michigan		X	X					X	X
Minnesota		X	X	X		X	X		X
Missouri		X			X			X	
Nevada		X			X	X			X
New Brunswick					X[14]				
New Mexico[15]				X	X	X			
New York	X[10]		X	X	X	X		X	X
North Carolina		X	X		X	X			

12 The utility DCFC investment in Florida is pending regulatory approval.
13 The residential charger incentive, the utility DCFC investment, the fleet support and managed charging in Kentucky are pending regulatory approval.
14 Utility DCFC investment in New Brunswick, Nova Scotia, Quebec and Rhode Island is unregulated.
15 The make ready investment, the utility DCFC investment and the fleet support in New Mexico are pending regulatory approval.

Table B-1
North American Electrification Initiatives

	Vehicle Incentive[1]	Commercial EV Charger Incentive[2]	Residential EV Charger Incentive[3]	Make Ready Investment[4]	Utility DCFC Investment[5]	Fleet Support[6]	Custom Commercial Incentive[7]	DCFC Incentive[8]	Managed Charging[9]
North Dakota			X				X		
Nova Scotia					X[14]				
Ohio[16]		X	X	X	X	X		X	X
Oregon		X	X		X	X			X
Pennsylvania	X	X							
Quebec	X[10]		X[10]		X[14]				
Rhode Island				X	X[14]	X		X	X
South Carolina			X		X				X
South Dakota			X				X		
Texas		X	X			X	X	X	X
Utah	X	X	X	X					X
Vermont	X	X	X						
Virginia		X	X		X	X			
Washington		X	X	X[17]	X	X			X
Wisconsin		X	X	X		X			
Total	**11**	**19**	**26**	**15**	**24**	**20**	**11**	**7**	**25**

16 The residential charger incentive, the utility DCFC investment, the fleet support and managed charging in Ohio are pending regulatory approval.
17 The make ready investment in Washington is pending regulatory approval.

Schedule C
2020–2034 Potential Study

FINAL REPORT (VOLUME 1 – RESULTS)

Conservation Potential Study

dunsky

Conservation Potential Study

Final Report (Volume 1 – Results)

Submitted to:

Newfoundland Power Inc.
Newfoundland and Labrador Hydro

Prepared by:

Dunsky Energy Consulting (6893449 Canada Inc.)

Contact:
Alex J. Hill
Managing Partner
50 Ste-Catherine St. West, suite 420
Montreal, QC H2X 3V4

T: 514 504 9030 ext. 30
E: alex.hill@dunsky.com

CONTENTS

Volume 2

Within the text of the report the reader will find references to specific appendices in which further relevant details are presented. Appendices are included in Volume 2 as follows:

Appendix A: Energy Efficiency modelling methodology

Appendix B: Demand Response modelling methodology

Appendix C: Fuel Switching modelling methodology

Appendix D: Electric Vehicle adoption modeling methodology

Appendix E: Study inputs and assumptions

Appendix F: Detailed results tables

LIST OF FIGURES

LIST OF TABLES

LIST OF ACRONYMS

ASHP – Air Source Heat Pump

BEV – Battery Electric Vehicle

BUG – Backup Generator

CBR – Cost Benefit Ratio

CDM – Conservation and Demand Management

CEUS – Commercial End-Use Survey

CPP – Critical Peak Pricing

CVR – Conservation Voltage Reduction

DCFC – Direct Current Fast Charger

DEEP – Dunsky Energy Efficiency Potential Model

DHW – Domestic Hot Water

DMSHP – Ductless Mini-Split Heat Pump

DR – Demand Response

EE – Energy Efficiency

ER – Early Replacement

EUL – Estimated Useful Life/Effective Useful Life

EVA – Electric Vehicle Adoption Model

RCx – Retro-commissioning

FS – Fuel Switching

GHG – Greenhouse Gas

GWh – Gigawatt Hour

HDV – Heavy Duty Vehicle

HVAC – Heating, Ventilation, and Air-Conditioning

ICE – Internal Combustion Engine

IIC – Island Interconnected System

IOC – Iron Ore Company of Canada

ISO – Isolated Diesel System

ISP – Industry Standard Practice

kWh – Kilowatt Hour

L2 – Level 2

LAB – Labrador Interconnected System

LDV – Light Duty Vehicle

LED – Light-Emitting Diode

MDV – Medium Duty Vehicle

MW - Megawatt

MWh – Megawatt Hour

NTGR – Net-to-Gross Ratio

PACT – Program Administrator Cost Test

PC – Participant Cost

PCT – Participant Cost Test

PHEV – Plug-in Hybrid Electric Vehicle

ROB – Replace on Burnout

RUL – Remaining Useful Life

SCT – Societal Cost Test

SEM – Strategic Energy Management

TCO – Total Cost of Ownership

TOU – Time-of-Use

TRC – Total Resource Cost

TRM – Technical Reference Manual

VFD – Variable Frequency Drive

VRF – Variable Refrigerant Flown

DEFINITIONS

Assessment of potential: The development of energy and capacity savings available from projected customer usage through the application of commercially available, cost-effective technologies and improved operating practices, considering the impacts of market factors.

Achievable potential: The savings from cost-effective opportunities once market barriers have been applied, resulting in an estimate of savings that can be achieved through demand-side management programs. Three achievable potential scenarios were modeled to examine how varying factors such as incentive levels and market barrier reductions impact uptake.

Cumulative savings: A rolling sum of all new savings that will affect energy sales, cumulative savings exclude measure re-participation (i.e. savings toward a measure are counted only once, even if customers can participate again after the measure has reached the end of its useful life) and provide total expected grid-level savings.

Economic potential: The savings opportunities available should customers adopt all cost-effective savings, as established by screening measures against the Total Resource Cost (TRC) test, without consideration of market barriers or adoption limitations.

Energy End-Use: In this study, energy end-uses refer to grouping of energy saving measures related to specific building component (i.e. water heating, HVAC, lighting etc.)**.**

Energy Saving Measure: An energy saving measure (or measure) refers to a specific equipment or building operation improvement that leads to energy savings.

Market Sector: The market of energy using customers in Newfoundland and Labrador is broken down into two sectors based on the primary occupants in the building: Residential (including single family and multi-family buildings) or Commercial (including businesses, institutional and industrial buildings).

Market Segment: Within each Sector, market segments are defined to capture key differences in energy use and savings opportunities that are governed by building use and configuration.

NL Utilities: Refers to the two retail utilities in Newfoundland and Labrador, Newfoundland Power (NF Power) and Newfoundland and Labrador Hydro (NL Hydro).

Program savings: Savings from measures that are incentivized through programs in a given year, including savings from measure re-participation. They are most representative of annual program savings and can be used to improve CDM program planning to help meet savings objectives, and to determine which sectors, end-uses, and measures hold the most potential.

Technical potential: The theoretical maximum savings potential, ignoring constraints such as cost-effectiveness and market barriers.

EXECUTIVE SUMMARY

Dunsky Energy Consulting conducted a Conservation and Demand Management (CDM) potential study for Newfoundland and Labrador over the 2020-2034 timeframe. Detailed bottom-up modeling tools were applied, to quantify energy and demand impacts from multiple CDM sources, including energy efficiency (EE), demand response (DR), heating fuel switching (FS) and electric Vehicles (EVs).

The study covered opportunities in each of the three electricity systems in the province:

- The Island Interconnected (IIC) System: Comprising over 90% of the provinces' residential and commercial customers.
- The Labrador Interconnected System (LAB): On which consumption is dominated by two large industrial customers.
- The Isolated Diesel (ISO) Systems: Which make up a small portion of electricity consumption in the province but have extremely high generation costs and barriers to efficiency.

Table 0- 1 provides a guide of the electricity systems that each study element was applied to.

Table 0- 1. CDM Programing Components Covered in the NL Conservation Study

Study Component	Model Applied	Systems Studied
Energy Efficiency	Dunsky's Energy Efficiency Potential (DEEP) Model	IIC, LAB, ISO
Demand Response	Dunsky's Demand Response (DR) Model	IIC, LAB
Fuel Switching	DEEP Model adapted for Heat Pump adoption	IIC
Electric Vehicles	Dunsky's Electric Vehicle Adoption Model	Province-wide

The study is founded on up-to-date Newfoundland and Labrador-specific market data for both the residential and commercial sectors. This market data provided specific saturation and baseline efficiencies of energy-using equipment in homes and businesses across the province. In addition, the study included a survey to assess customer barriers to the adoption of energy efficiency technologies.

This potential study comes at a transitional time for Newfoundland and Labrador's electric utilities, stemming from changes to the province's generation and transmission systems. This is taking place against disruptions to North America's electricity utility industry as a whole, including a growing focus on customer needs and their opportunities to save energy, shift demand and switch fuels. Specific challenges facing the electric utilities include:

- Changes to Newfoundland and Labrador's energy supply and distribution with the addition of the Muskrat Falls generation facility and Labrador-Island-Link transmission line.
- Changes to marginal costs of energy and peak demand.
- A rapidly transforming lighting market, which is impacting some CDM program top savings measures.
- A growing interest in the electrification of heating and transportation.
- The emergence of peak demand and load management priorities.

These opportunities put growing emphasis on conservation and demand management opportunities that can help utilities balance supply and demand, considering both temporal and locational variations, to maintain electricity service reliability and affordability.

Over the 15-year study period, electricity rates, avoided costs and carbon pricing in the province are subject to notable uncertainty. To capture the impact that changes in these factors could have on the market adoption of the studied technologies, sensitivity analyses were conducted covering these three key economic factors.

USES FOR THIS POTENTIAL STUDY

This potential study is a high-level assessment of electricity impacting opportunities in the Province of Newfoundland and Labrador over the next 15 years. Its main purposes are to support:

- **Resource planning:** Evaluate the impact of Energy Efficiency, Demand Response, Fuel Switching and Codes & Standards on long-term energy consumption and demand needs at the grid/distribution level.
- **Efficiency program planning:** Assess achievable CDM opportunities to improve CDM program planning and help meet long-term savings objectives, and determine which sectors, end-uses and measures hold the most potential.

This potential study is *not* intended to give granular information about measures in specific segments, but rather give a macro view of efficiency potential. Moreover, it is not a program design document that accurately forecast savings achieved through Utility programs in a given future year, but rather quantify the total potential opportunities that exist under specific parameters.

ENERGY EFFICIENCY POTENTIAL

Three levels of savings potential were assessed: Technical, Economic, and Achievable. Within the Achievable potential three scenarios were modeled to examine how CDM program design factors such as incentive levels and investments in enabling activities can impact potential savings. The achievable potential scenarios are defined at the Upper, Mid, and Lower Achievable Potential levels, as described in **Figure 0-1** below.

Figure 0-1. CDM Program Scenarios Applied in this Study

Lower

- **Lower Achievable Potential**
  Applies current Utility CDM program incentive levels and enabling activities, but includes the full range of cost-effective technologies, and disregards any budget constraints.

Mid

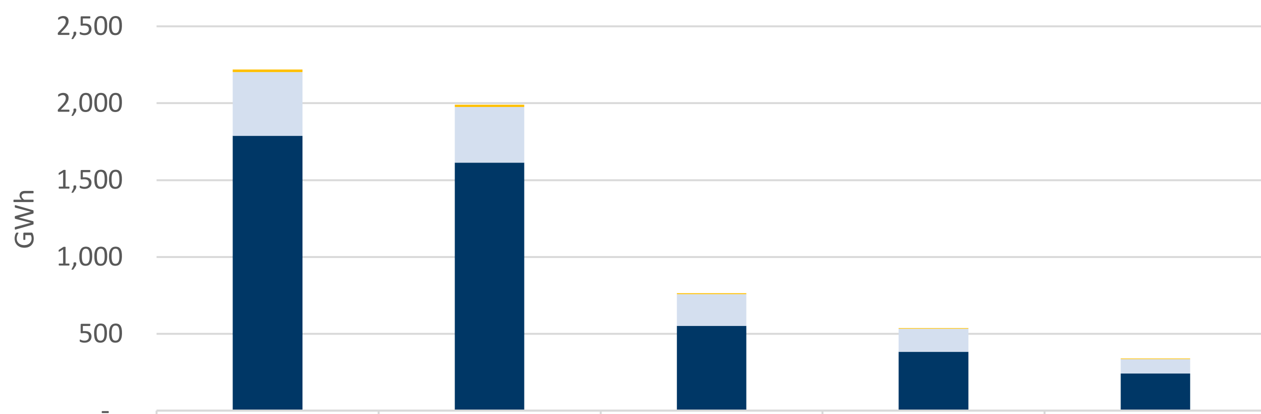
- **Mid-Range Achievable Potential**
  Applies increased incentive levels to reflect increased investments in CDM programs compared to the current portfolio.

Upper

- **Upper Achievable Potential**
  Applies increased incentive levels, and includes further investments in enabling activities to address customer barriers to adoption.

Below, the technical, economic, and achievable savings are presented side-by-side for electric potential savings (**Figure 0-2**) for each system over the study period (2020-2034). Overall these results show that over 95% of the Technical Potential is cost-effective (from a total resource cost (TRC) test perspective) and is therefore captured in the Economic Potential. Moreover, the Achievable Potential scenarios demonstrate the impact of additional investments through higher incentive levels and further enabling strategies.

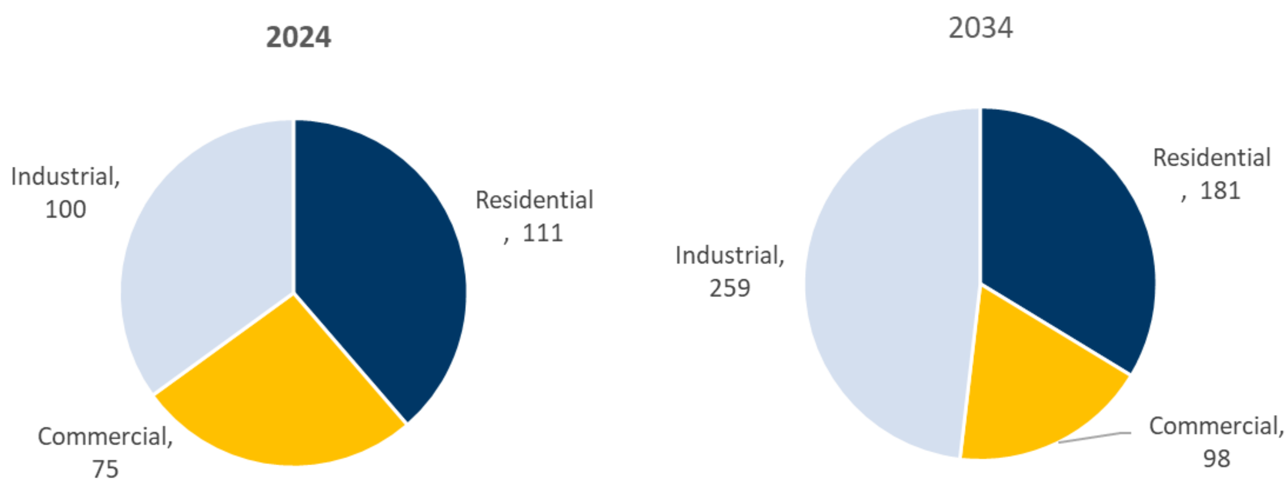
Figure 0-2. Cumulative Electric Potential Savings from Efficiency Under Mid-Rates (2034)



	Technical	Economic	Upper	Mid	Lower
ISO	16	16	6	5	4
LAB	415	363	207	149	94
IIC	1,788	1,613	552	384	242

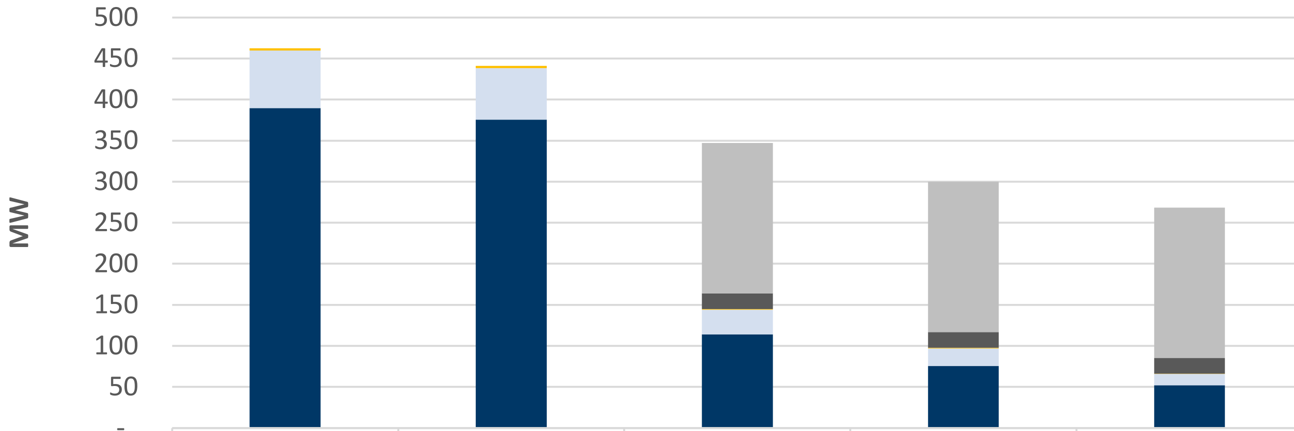
Below, cumulative savings under the Mid program scenario are presented by sector and time period (**Figure 0-3**). The results presented focus on the Mid program scenario for illustrative purposes, as the proportional amount of savings in each sector are generally consistent under each of the program scenarios. Overall the results show that in the initial years the residential sector offers the greatest savings potential, while the industrial sector offers the greatest potential by the end of the study. This is primarily a result of the residential lighting savings being eliminated after 2025 as the lighting market transforms as result of the new EISA standards that are expected to come into force. It should be noted that the majority of the industrial savings come from the Large Industrial segment, for which a top-down assessment was performed, rather than the bottom-up analysis applied to assess savings in all other segments.

Figure 0-3. Province-Wide Cumulative Achievable Potential (GWh) by sector: Mid Program Scenario



The combined peak demand potential from energy efficiency (EE) and demand response (DR) programs are presented below in **Figure 0-4** below.

Figure 0-4. Peak Demand Potential Savings for DR and EE Programs by System[1] Under Mid-Rates (2034)



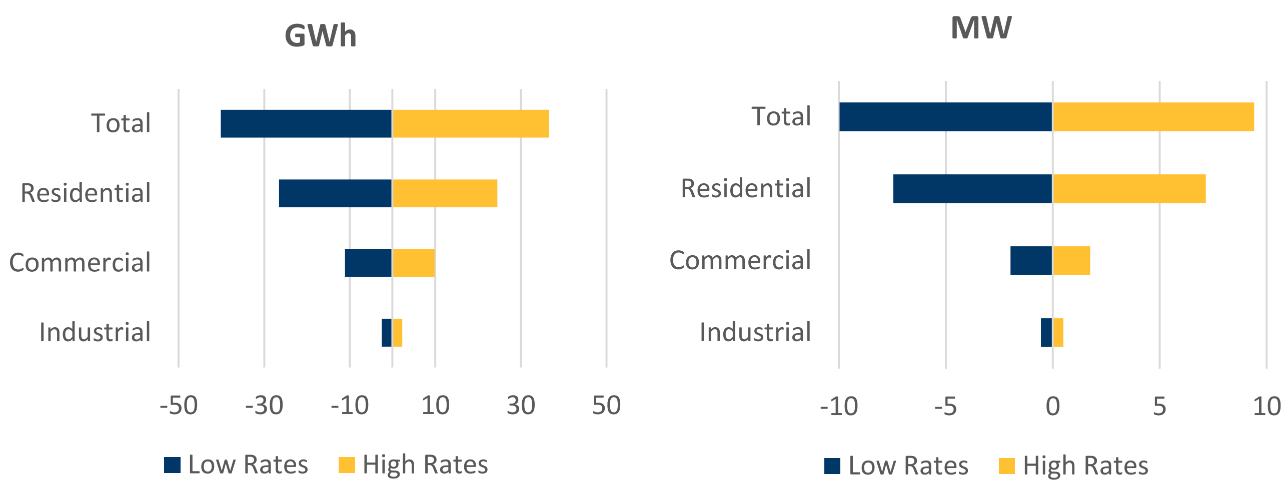
	Technical	Economic	Upper	Mid	Lower
IIC (DR)			183	183	183
LAB (DR)			19	19	19
ISO (EE)	3	3	1	1	1
LAB (EE)	70	63	30	22	14
IIC (EE)	390	375	114	76	52

Overall, from these findings it is evident that EE program scenarios offer significant demand reduction potential, particularly in the IIC system. However, it is also apparent that the DR programs offer more peak demand reductions than any of the EE program scenarios.

Figure 0-5 below shows the impact of the low and high customer rate cases on the Mid Program scenario cumulative achievable potential by 2034. The low customer rate represents customer rates that are fully mitigated from future rises related to the Muskrat Fall generation facility (about 18% less than the Mid-case), while the High rates case represents a scenario where the rates are not mitigated at all (about 20% higher than the Mid rates scenario). Overall it is found that the achievable potential will increase or lower by 10% under each rate case as compared to the mid-rates case. These results are somewhat tempered by the fact that the rate cases were not applied to the Large Industrial sector, which delivers nearly half of the achievable potential by 2034.

[1] DR potentials include existing curtailment and potential peak demand impacts from new measures and programs as described in Chapter 4 of this report. Because the model does not consider interactions among DR measures at the technical and economic potentials level, the results are not considered additive, and are therefore not included in the graph.

Figure 0-5. Impact of Customer Rate Scenarios on Cumulative Achievable Savings by segment: Mid Program Scenario (IIC - 2034)



Finally, the study assessed the annual activity and savings for each of the takeCHARGE programs. The overall results, where savings are expressed as the portion of sales in each year, are presented below for the IIC and LAB systems together (**Figure 0-6**) and the ISO system (**Figure 0-7**). Overall it was found that annual program savings are highest in the initial years, and drop after 2024 when the new EISA lighting standards are expected to come fully into force. Savings in the earlier years contain significant lighting contributions while in the later years, envelope, HVAC and industrial motors and compressors dominate the program savings.

Figure 0-6. Program Savings as a Portion of Annual Sales: Lower, Mid and Upper Program Scenarios Under Mid Rates (IIC+LAB)

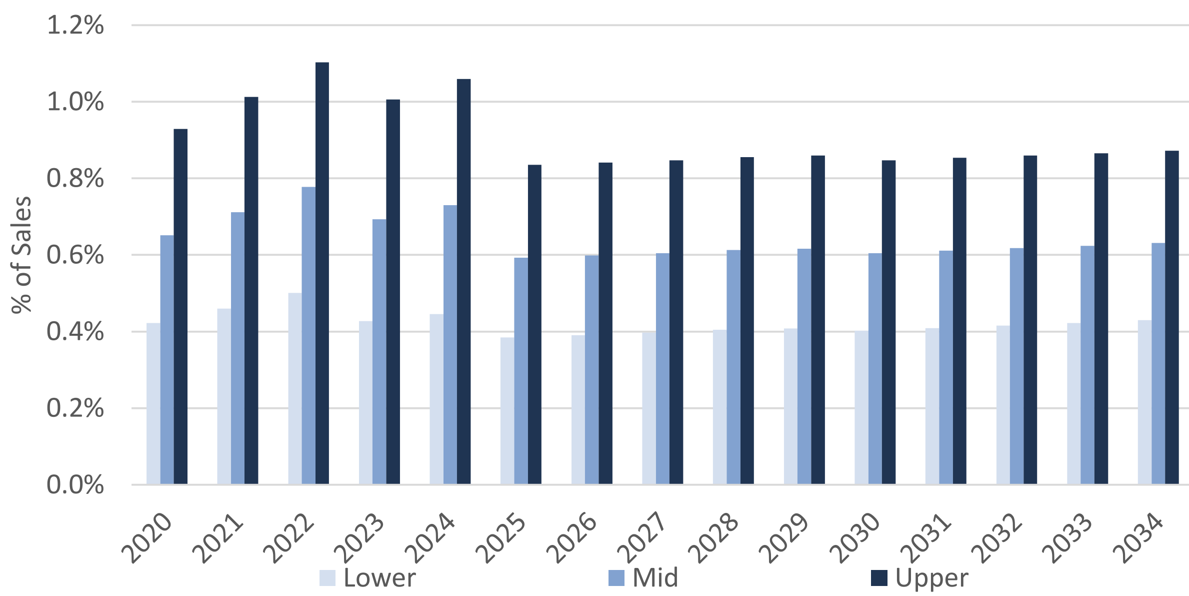
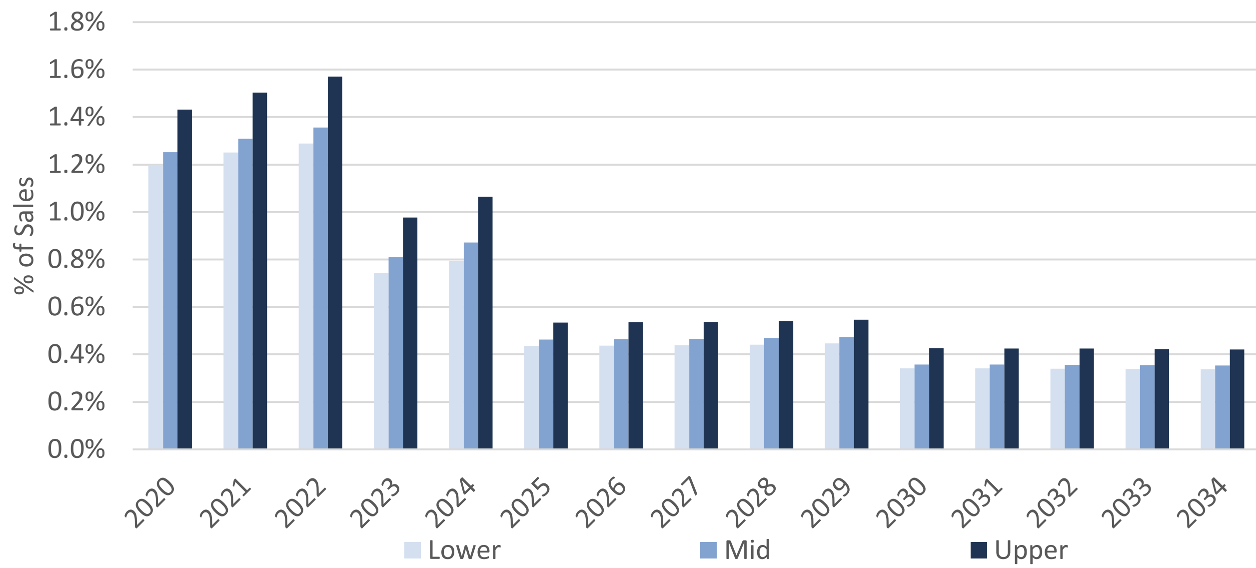


Figure 0-7. Program Savings as a Portion of Annual Sales: Lower, Mid and Upper Program Scenarios Under Mid Rates (ISO)



CDM PROGRAMS: KEY TAKE-AWAYS

The following key take-aways emerge from the CDM Program potential analysis:

- **The province-wide savings in the initial study years put the NL Utility CDM programs squarely in the range of savings being achieved by other Canadian utilities**. The Lower program scenario potential would correspond to closely current CDM program savings, but with an increase stemming from the expected increase in customer rates as the Muskrat Falls generation facility comes online. Savings in this period are dominated by substantial lighting savings when summed across all sectors, a trend that is particularly strong in the ISO system.

- **In the residential sector annual savings are highest for Home Energy Reports, but Envelope measures offer the greatest lifetime saving:** As much as 50% of annual savings come from the Home Energy Reports. However, this program offers limited lifetime savings, due to its 1-year EUL. Envelope measures provide significant annual savings and more than half of all lifetime savings by the end of the study period.

- **Commercial sector savings are initially dominated by lighting, but in the later years HVAC measures present a leading opportunity.** With four measures in the top 10 in the latter study years (HVAC Control, HVAC VFD, HVAC Equipment and Heat Pumps), the HVAC end-use shows the second most potential for program savings, starting after EISA standards come into effect (2023). It also has the greatest potential in terms of lifetime savings during the entire study period. This may justify focusing CDM efforts on this end-use.

- **Industrial sector savings are driven by the large industrial segment. Motors and compressor measures related to processes dominate the program savings in all periods.** The industrial sector also offers notable lighting savings, as most industrial lighting is not impacted by the new EISA lighting standards.

Finally, HVAC measures also offer notable savings for industrial facilities where they have high annual hours of use (24-hour operation or shift work).

DEMAND RESPONSE POTENTIAL

The study includes an assessment of the technical, economic and achievable potentials of a wide range of demand response (DR) measures, and the results are presented for each set of measures under the achievable potential scenario results. Three DR program scenarios were assessed, each based on a specific mix of DR programs to determine which offers the most potential when the net impact on the utility peak demand curve is assessed (**Figure 0-8**).

Figure 0-8. Demand Response Program Scenarios

Scenario 1

- **Enhanced Current DR Potential**
  The first scenario focuses on maximizing the impact from current DR programs (i.e. curtailment) and adding further programs that have little or no interactive effects with existing programs.

Scenario 2

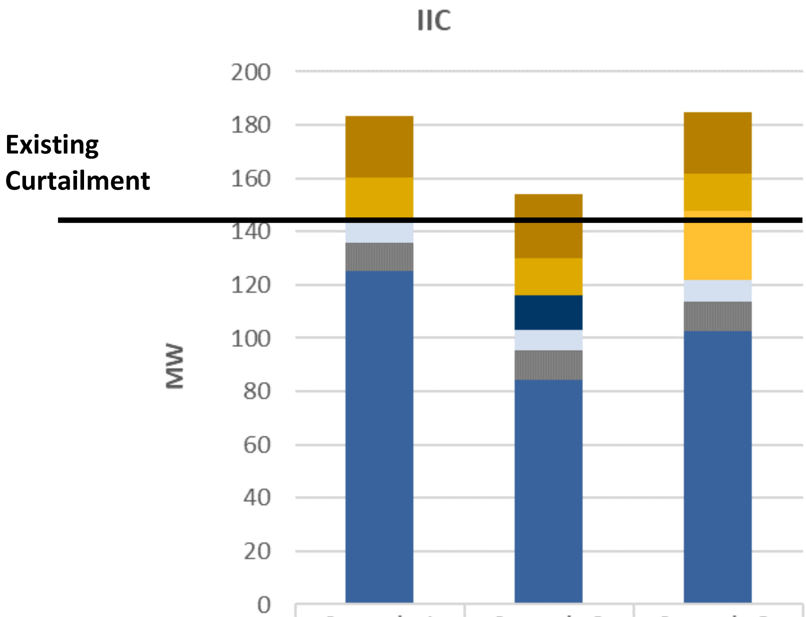
- **Rate-Based DR Expansion**
  The second scenario approach focuses on the DR potential possible via rate-based measures such as Time of Use rates and/or Critical Peak Pricing. These are applied alongside existing curtailment programs.

Scenario 3

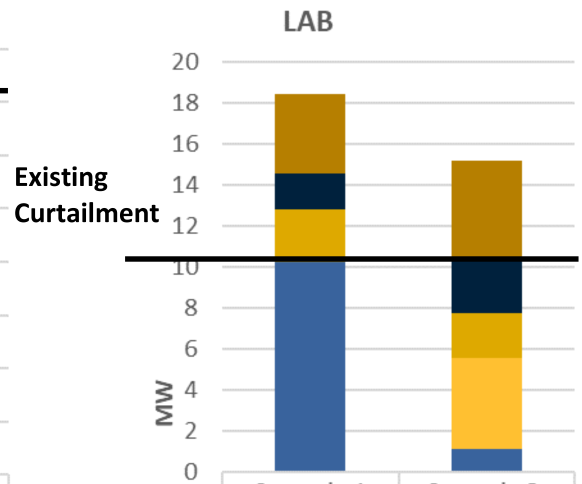
- **Equipment Control DR Expansion**
  The third scenario focuses on an equipment control approach, either through utility direct load control, or manual control of equipment. These are applied alongside existing curtailment programs.

Figure 0-9 and **Table 0-2** below present the peak reduction potential for each scenario assessed for the IIC and LAB systems. A line indicating the peak demand reduction potential from the existing industrial and commercial curtailment as well as conservation voltage reduction (IIC system only) is also included.

Figure 0-9. Demand Response Potential[2] (2034)



	Scenario 1	Scenario 2	Scenario 3
Dual-Fuel	23	24	23
Small/Med Industrials	16	14	14
Equipment	0	0	26
TOU	0	13	0
CVR	8	8	8
Commercial Curtailment	11	11	11
Large Industrials	125	84	103



	Scenario 1	Scenario 3
Dual-Fuel	4	5
BUGs	2	3
Small/Med Industrials	3	2
Equipment	0	4
Large Industrials	10	1

[2] Since dynamic rates have a negative impact on LAB system, Scenario 2 is not present in the LAB analysis. The following sections and Appendix F contain more details on dynamic rates and their impacts on LAB and IIC systems.

Table 0- 2. Existing Curtailment and Scenarios Comparison (2034)

System	Existing potential	Scenario 1:	Scenario 2:	Scenario 3:
IIC	144	183	154	185
LAB	10	19	19[3]	15
Total	**154**	**202**	**173**	**200**

From the above results the following conclusions can be drawn:

- **Scenario 1 - Optimizing the Existing Curtailment is the most advantageous scenario:** Scenario 1 offers the most potential for nearly all years for both IIC and LAB systems. The focus on the existing curtailment approaches carries the least degree of program complexity and cost when compared to Scenarios 2 and 3 that would require adding the program infrastructure for TOU rates and equipment direct load controls respectively.

- **In the IIC systems there is little benefit, or even lowered peak reduction benefits, in adding measures that incur significant bounce back effects:** Under Scenario 2 in the IIC system, the overall potential actually drops when the optimally designed TOU rates program is added to the mix of programs as it undermines the ability for the Industrial Curtailment program by creating new, choppier peaks in the load curve. Scenario 3 in the IIC system does yield a marginally higher overall potential (2 MW higher) than Scenario 1.

- **Existing industrial curtailment potential places Newfoundland and Labrador at the high end of achievable range when benchmarked against other jurisdictions:** The Industrial Curtailment program has significant enrolled capacity that appears to be well suited to reducing peak loads on the IIC system in particular. Further potential may exist to expand this program among more Small and Medium industrial customers as well.

  While TOU Rates, CPP and Equipment Control programs did not appear to offer additional DR potential, adjustments to the existing Industrial Curtailment programs, incorporating more aggressive EV adoption peak load impacts, or adding the Fuel Switching load curve impacts, all may alter conditions such that TOU Rates, CPP and/or Equipment Controls could become effective in the future: Changes to the utility load curve or to the constraints applied in other programs have significantly impacted the interactions among programs. For example, if the NL Utilities are able to negotiate Industrial Curtailment contracts with longer DR event durations, it may be possible that TOU Rates, CPP and Equipment Programs could offer additional potential as compared to the results presented herein.

Overall, it appears that maintaining the Utilities focus on industrial and commercial curtailment is the best option to optimize the DR achievable potential in NL.

---

[3] Using best scenario (Scenario 1: Optimise Existing Curtailment) since TOU is not improving peak demand savings for LAB system.

Consideration of Curtailment Flexibility and Further Integration of EV Adoption and Fuel Switching Impact

Increased flexibility for the industrial curtailment contracts could increase the potential from other programs. Further analysis of this potential will be undertaken by the Utilities. It should also be noted that the results presented in study indicate that Fuel Switching and EV Adoption could significantly alter the utility load curve shapes, which may create an opening for the TOU Rates, CPP and Equipment Controls programs to add further peak load reduction potentials. As the needed information becomes available, the Utilities will conduct further assessments.

FUEL SWITCHING POTENTIAL

A fuel switching analysis was conducted to assess how many households and businesses can be expected to replace or supplement oil- and wood-fired space heating and domestic hot water (DHW) heating systems with electric heat pump systems under various levels of incentives. The analysis tested three scenarios – one without any incentives (Lower) and two with various levels of utilities incentives to encourage customers to install electric heating and hot water equipment (Mid, Upper) under the Mid-rate scenario with no carbon tax applied to fuel oil for heating. The incentive scenarios also reduce barrier levels in the model to simulate education and outreach efforts that make fuel switching less daunting to consumers. **Figure 0-10** describes each scenario.

Figure 0-10. Fuel Switching Scenarios Applied in this Study

Lower	•**No Incentives** No incentives are offered. Fuel switching is what would be expected without any market intervention.
Mid	•**35% Incentive** An incentive to cover 35% of the incremental cost of the measure is applied, **plus a ½ step reduction in barrier levels**.
Upper	•**70% Incentive** An incentive to cover 70% of the incremental cost of the measure is applied, **plus a full step reduction in barrier levels.**

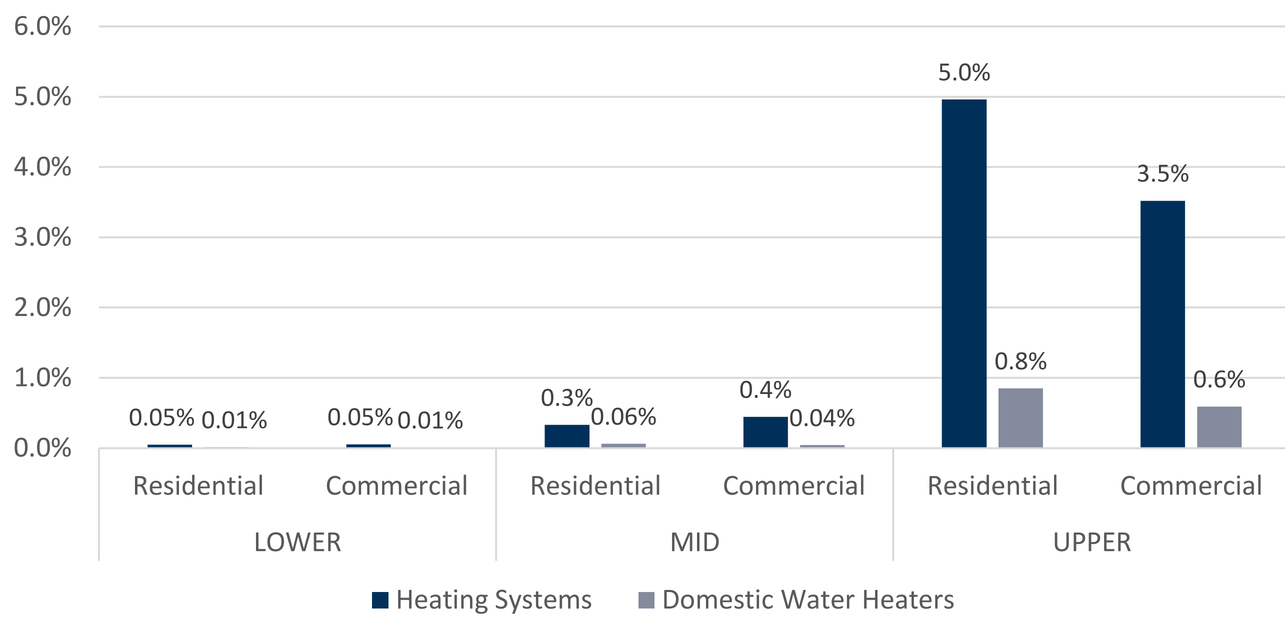
Figure 0-11 shows the portion of customers that would be expected to switch from combustible fuel systems (i.e., oil-fired or wood-fired heating systems) to heat pump systems under each scenario. Ultimately, there is little adoption of heat pump measures by oil-heated households and businesses when no incentives are provided (Lower scenario). Wood-heated households do not adopt heat pump measures under any scenario. The only

significant adoption under the Lower scenario is DMSHPs by households with electric baseboard heating (not shown in figure), which drives significant reductions in energy consumption and demand.[4]

With a smaller incentive (e.g. Mid scenario), oil-heated customers begin to adopt heat pump systems, but the market does not move significantly until large incentives are provided under the Upper scenario. With a 70% incentive (plus full step barrier level reduction by applying enabling strategies such as customer and contractor education), 5.0% of all residential customers and 3.5% of all commercial floor space opt to replace or displace their oil-fired heating system with a central air source heat pump (ASHP) or ductless mini-split heat pump (DMSHP). Nearly all heat pumps adopted by the commercial sector are DMSHP, while roughly 80% of heat pumps adopted by the residential sector are DMSHP – the remainder being central ASHP.

Finally, there is little adoption of heat pump domestic water heaters (DWH) under the Lower and Mid scenarios. Under the Upper scenario, 0.8% of residential and 0.6% of commercial customers switch from oil-fired DWH to heat pump DWH, respectively.

Figure 0-11. Percent of customers switching from combustible fuel systems to heat pump systems (2034)



Note: For heating systems, residential adoption is expressed as a percentage of households, while commercial adoption is expressed as a percent of square footage.

Figure 0-12 and **Figure 0-13** show the energy and demand impacts of fuel switching netted against the energy and demand reductions expected from electric baseboard households adopting DMSHP.

[4] Note: The addition of DMSHP to households with electric baseboard heating is not incentivized under any scenario since there is significant natural adoption without incentives, and this measure would not typically pass utility cost-effectiveness screening.

Figure 0-12. Fuel switching net energy impact (Mid-rates case)

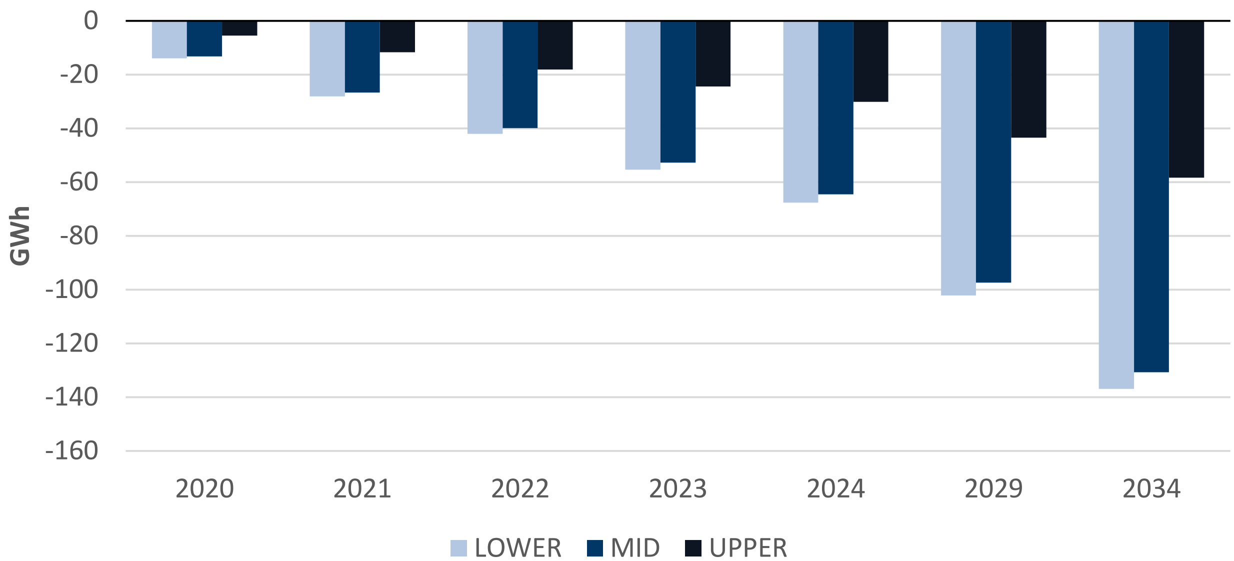
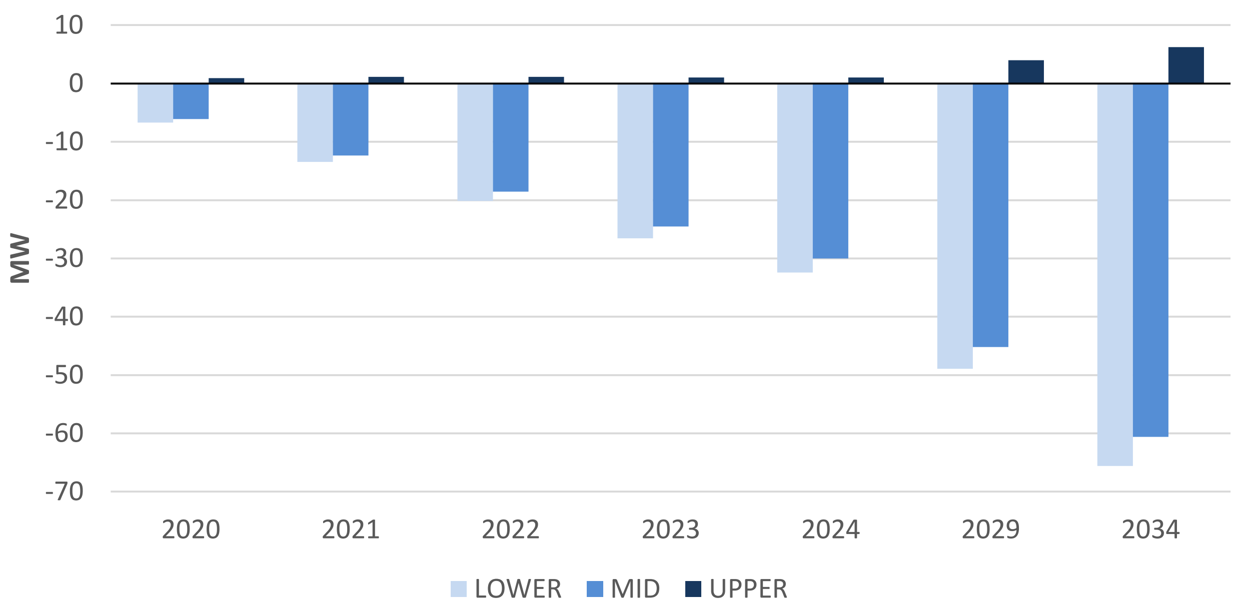


Figure 0-13. Fuel switching net demand impact



Note: Incentives are not provided to households with electric baseboard heating under any scenario.

Based on the fuel switching analysis, the following key findings emerge:

- **The customer's economics *do not* favour fuel switching from oil or wood fired space heating.** For most customers, it does not make sense to adopt electric-based heating systems (space heating or domestic water heating) in favour of existing oil- and wood-fired heating systems – even when the electric systems are high efficiency heat pumps. Without significant incentives, consumers are unlikely to switch from combustible fuel-based systems to any sort of electric heating including heat pumps. This tendency will only be magnified if electricity rates increase faster than assumed under the Mid-rates case.

- **The customer's economics *do* favour heat pumps in existing electric resistance heated households.** The market segment where heat pump systems do show the most economic benefit is households with electric baseboard heating. The analysis mirrors recent market data showing significant adoption of DMSHPs among households with electric baseboard heating, which leads to energy and demand reductions. If electric rates increase, the economics will only improve for these customers leading to additional adoption and additional reductions in electricity sales.
- **Incentivizing the addition of DMSHP to existing oil-fired heating systems offers the most opportunity to increase electricity usage.** Most customers adopted DMSHPs to displace heating from existing oil-fired heating systems, if they adopted anything at all. This choice avoids the costs associated with fully removing the legacy heating systems (e.g. oil tank removal).

ELECTRIC VEHICLE POTENTIAL

This study assesses the potential Electric Vehicle (EV) adoption in Newfoundland and Labrador and the corresponding impacts on electricity consumption in the province. Leveraging Dunsky's Electric Vehicle Adoption (EVA) model, the adoption of EVs within Newfoundland and Labrador is forecasted under several scenarios, energy consumption is assessed, the peak load and financial impacts of EV deployment are quantified and potential strategies for interventions are identified.

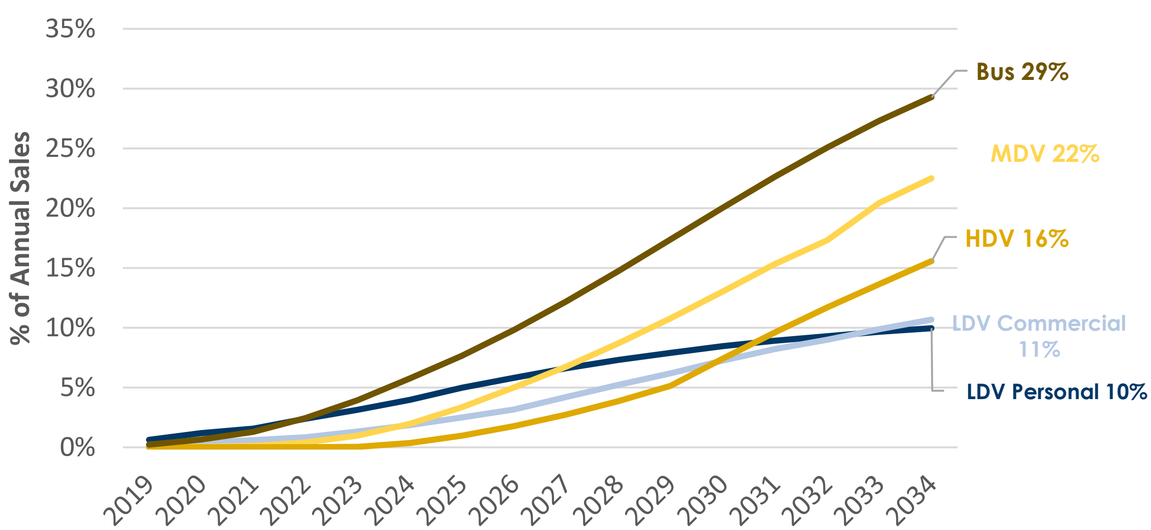
For this assessment the vehicle market in Newfoundland and Labrador was divided into the following five categories: Personal Light-Duty Vehicle (LDV), Commercial Light-Duty Vehicles (LDV), Medium-Duty Vehicles (MDV), Heavy-Duty Vehicles (HDV) and Buses. For each of the modeled vehicle categories, a vehicle archetype capturing representative characteristics (e.g. annual distance traveled, fuel efficiency, battery size, powertrain output, etc.) of a vehicle in that segment was developed.

The study then uses Newfoundland and Labrador specific inputs and assumptions to assess the potential for EVs in each vehicle category and assess corresponding opportunities and challenges. The following scenario analysis was conducted to assess the impact of a range of key factors on EV adoption in the province:

- **Baseline (business-as-usual):** EV adoption under no further action beyond currently planned deployment (i.e. no new installed charging infrastructure or incentives, except those currently committed to by the Utilities and the Provincial Government).
- **Sensitivities:** Impact of factors linked to general competitiveness of the global EV market (battery costs, vehicle availability) and local market conditions (electricity rates, fuel rates and vehicle sales).
- **Levers:** Interventions that the utility, government, or other actors can make to accelerate the deployment of electric vehicles, namely public DC Fast Chargers (DCFC) and Level 2 (L2) charging infrastructure deployment, as well as vehicle purchase incentive programs.

Figure 0-14 provides EV adoption projections under baseline conditions. Approximately 41,400 EVs are expected to be on the road by 2034, representing between 10-29% of annual sales varying by vehicle class.

Figure 0-14. Baseline Percent of Electric New Vehicle Sales by Vehicle Class



Key findings from the Baseline analysis include:

- **The adoption of Light-Duty Vehicles in Newfoundland and Labrador is well below national and global projections** (30% of EV sales by 2030), with only 10% of personal LDV sales and 11% of commercial LDV sales estimated to be EVs by 2034. This is primarily caused by the lack of public charging infrastructure, which is forecast to significantly constrain the growth of the LDV market moving forward. Despite the early lead of personal LDVs, commercial vehicles are expected to significantly increase in share during the study period as a result of improving economics.

- **The forecast uptake of MDVs and HDVs in Newfoundland and Labrador are on par with global projections.** Given lower anticipated dependence of commercial light-duty vehicles on public infrastructure, incremental upfront purchase cost and model availability become the primary barriers to uptake in these segments and as these factors improve over the course of the study period, uptake increases in response.

- **The natural uptake of electric buses significantly exceeds that of all other vehicle classes reaching 29% of sales by 2034.** This is primarily due to high vehicle model availability and high utilization of some bus types which improves the business case from a total cost of ownership perspective.

- **EVs could represent 3% of electricity consumption by 2034:** Despite light-duty personal vehicles representing the majority of EVs on the road at all points in the study period, the majority of load impacts would likely come from the MDV, HDV and Bus classes given the higher utilization and size of these vehicle types and corresponding energy use. Overall under the baseline scenario, EVs are estimated to add 266 GWh of electricity consumption by 2034 (≈ 3% of energy sales) and contribute to a 100 MW increase in the utilities' peak demand (≈ 5% of forecast peak by 2034).

A sensitivity analysis to test the impact of key uncertainties indicates that vehicle model availability in the short-term will be critical for EV adoption. Additionally, commercial segments were found to be more sensitive to economic factors that impact the Total Cost of Ownership (TCO) of vehicles compared to the personal segment; particularly future electricity rates and fuel prices.

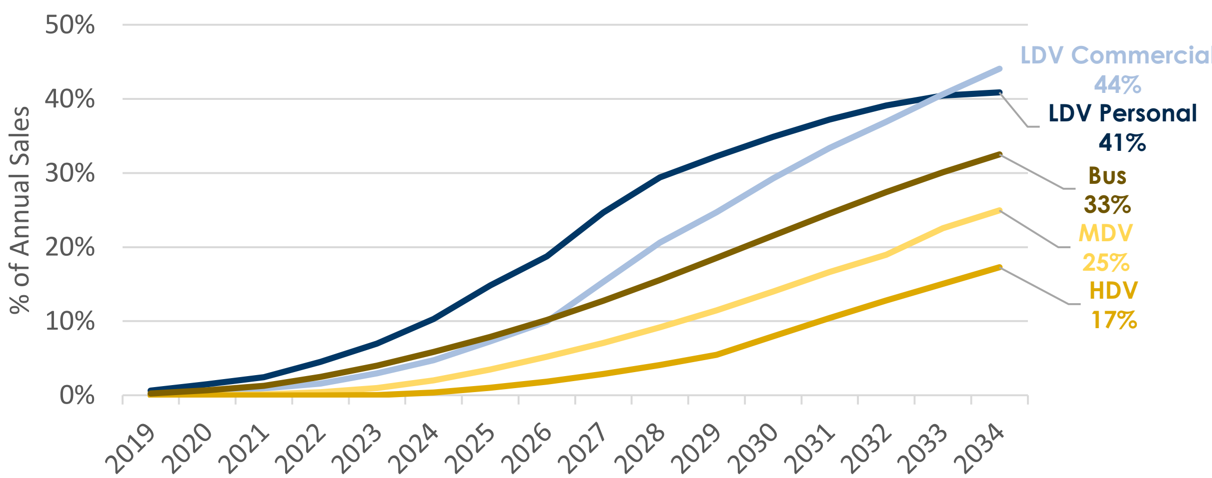
An analysis of the impact and cost-effectiveness of the three investment levers (DCFC, Level 2 and incentives) was conducted, which indicates that:

- **DCFC investments can have a significant impact in accelerating EV adoption and energy sales.** For example, a $20M investment in DCFC infrastructure would result in 132,000 EVs on the road (219% increase from baseline), and 647 GWh of EV load by 2034 (143% increase from baseline). Despite being identified as a priority, investments in DCFC beyond certain thresholds may result in over-saturating the market and are expected to have diminishing returns.
- **Level 2 charger investments were also found to be impactful and cost-effective, however less so than DCFC.** The impact of infrastructure investment could be maximized through leveraging existing federal programs or following a "make-ready" approach rather than self-deployment of charging stations.
- **Incentive programs could accelerate adoption in the short-term,** however they have limited long-term impact on the market compared to infrastructure deployment and may not be a suitable approach for intervention.

- **Investments should be diversified among complementing investments** in DCFC with public L2 deployment, education and awareness initiatives and programs targeted towards commercial fleets. For example, a modeled $20M investment focused on DCFC and L2 infrastructure can significantly increase LDV uptake in Newfoundland and Labrador, from 10% of sales in 2034 under baseline to 41% of sales by 2034; bringing EV adoption in Newfoundland and Labrador on par with Canada-wide and global EV sales targets.
- **The MDV, HDV and bus segments were found to be more sensitive to customer economics and will require substantial support in the form of incentives or changes in key financial factors** (electricity rates, fuel prices, etc.) to trigger any significant shift in adoption beyond natural market uptake.

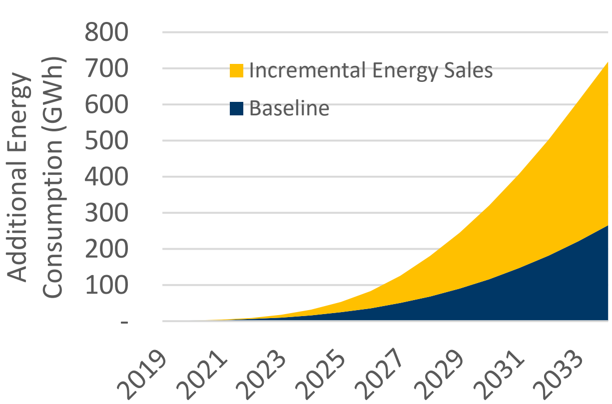
Figure 0-15 and **Figure 0-16** below show the adoption projections and electricity sales impacts of a diversified $20M investment over 10 years to promote EV adoption in the province.

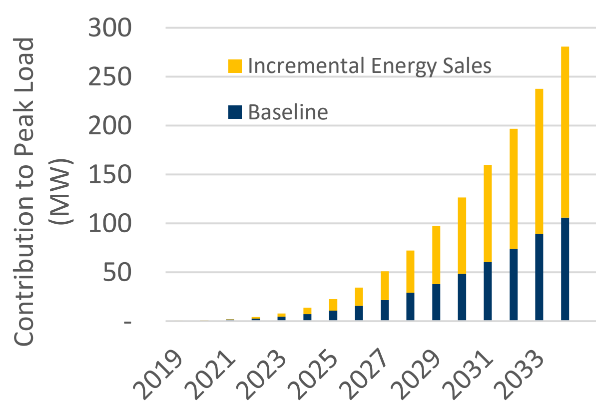
Figure 0-15. Percent of Electric New Vehicle Sales by Vehicle Class Under $20M Investment Scenario



The incremental adoption attributed to the investments can almost triple load growth from EVs relative to baseline to 720 GWh of energy consumption (approximately a 7% increase in 2034 energy consumption) and increase system peak demand by 281 MW (approximately a 13% increase in 2034 peak load) under unmanaged charging, as shown in **Figure 0-16.** EV charging load management could potentially reduce the peak impacts of the forecasted EV adoption to 42 MW (approximately 2% increase in 2034 peak load).

Figure 0-16. Energy and Peak Load Impacts from Electric Vehicle Adoption Under $20M Investment Scenario





Financial Impacts

The Utilities' high capacity costs coupled with the high coincidence between EV charging loads and utility loads are expected to lead to significant peak increases and costs to the Utilities that could result in deficits as well as diminish the value any investment brings. Under the baseline scenario, the Utilities are forecasted to incur losses of $44M by 2034 as a result of EV deployment if no load management is utilized or capacity costs are not reduced.

EV load management will be critical to enable the Utilities to handle the system impacts of EVs and benefit financially from EV adoption under baseline scenario as well as any investment scenario. As shown in **Table 0-3**, the modeled $20M investment can bring $170M in additional value to the Utilities by 2034 from the increased revenue in the presence of load management versus a loss of $113M under an unmanaged charging scenario.

The Utilities should thus prioritize initiatives that can reduce peak impacts of EV loads to unlock any revenue opportunities from EVs, which could contribute to utility efforts to mitigate projected electricity rate increases stemming from the Muskrat Falls generation facility.

Table 0- 3.Benefits and Costs of EV Adoption Under Baseline and $20M Investment Scenario By 2034

	Unmanaged Charging			Load Management		
	Benefits	**Costs**	**NPV**	**Benefits**	**Costs**	**NPV**
Baseline	$119M	($163M)	**($44M)**	$119M	($51)	**$68M**
$20M Investment	$317M	($359M)	**($113M)**	$317M	($147M)	**$170M**

REPORT STRUCTURE

This report presents the methods, findings and the potential study results from several perspectives, including cumulative savings by system, scenario, sector, segment, and end-use. A brief outline of the report structure is provided below.

VOLUME 1

Chapter 1 – Introduction: This first chapter provides an overview of the study scope and the context against which the study was conducted including the forecast baseline energy sales and peak demand projections. It also provides a description of the program scenarios and sensitivity analysis conducted in the study.

Chapter 2 – Cumulative CDM Program Savings Potential: The first results chapter section outlines cumulative savings over 15 years from CDM programs, expressed as the cumulative impact on sales for each electricity system (IIC, LAB, ISO) under each of the program scenarios (Lower, Mid, Upper). It also includes a sensitivity analysis considering the impact of electricity rate forecasts and avoided costs on the cumulative savings.

Chapters 3 – Program Savings Potential and Analysis: Chapter 3 provides detailed results for CDM program savings, focusing primarily on the Mid scenario[5] (which applies slightly increased incentive levels and expanded eligible measures compared to current CDM programs). Results include average annual program savings, as well as savings by sector, end-use, and segment. Top-10 contributing measures are presented for each sector. Corresponding budget, and savings in percentage of sales are also provided. This chapter also includes an analysis of the specific CDM programs considering their potential savings and cost-effectiveness under each program scenario.

Chapter 4 – Demand Response Potential: Chapter 4 outlines the demand response program potential based on three program combination scenarios for each of the IIC and LAB systems. The chapter describes key DR measures and program interactive effects when multiple new and existing DR measures are applied simultaneously. Finally, the impact and cost-effectiveness of each scenario is provided.

Chapter 5 – Fuel Switching: This chapter presents the results of the fuel switching analysis, which assesses how many households and businesses can be expected to replace or supplement oil- and wood-fired space heating and domestic hot water (DHW) heating systems with electric heat pump systems under various levels of incentives.

Chapter 6 – Electric Vehicle Adoption: This chapter presents results of the Electric Vehicle (EV) Adoption study, highlighting forecasts for EV uptake within Newfoundland and Labrador under several scenarios, assessing the corresponding impacts on the utilities' load and identifying strategies for interventions that can increase EV adoption.

[5] Other scenario results are provided in Appendix F.

VOLUME 2

Within the text of the report the reader will find references to specific appendices in which further relevant details are presented. Appendices are included in Volume 2 as follows:

Appendix A: Energy Efficiency modelling methodology

Appendix B: Demand Response modelling methodology

Appendix C: Fuel Switching modelling methodology

Appendix D: Electric Vehicle adoption modeling methodology

Appendix E: Study inputs and assumptions

Appendix F: Detailed results tables

1. INTRODUCTION

This report presents the results of the Conservation and Demand Management (CDM) Potential Study conducted over the 2020-2034 timeframe for the Newfoundland and Labrador electric utilities. Detailed bottom-up modeling tools were applied, to quantify energy and demand impacts from multiple CDM sources, including energy efficiency (EE), demand response (DR), heating fuel switching (FS) and electric Vehicles (EVs). This report provides an assessment and analysis of the combined CDM potential for Newfoundland and Labrador over the study period, as well as a high-level explanation of the study methods and modelling approach.

THE NEWFOUNDLAND AND LABRADOR ELECTRIC UTILITIES

NEWFOUNDLAND POWER INC.

Newfoundland Power Inc. operates an integrated generation, transmission and distribution system throughout the island portion of Newfoundland and Labrador.

For over 125 years, Newfoundland Power has provided customers with safe, reliable electricity in the most cost-efficient manner possible. Newfoundland Power serves over 265,000 customers, about 90% of all electricity consumers in the province.

Newfoundland Power purchases approximately 93% of the electricity it sells from the Crown Corporation, Newfoundland and Labrador Hydro. Newfoundland and Labrador Hydro are the primary generation utility on the island interconnected system. Newfoundland Power generates the balance from its generation facilities, primarily smaller hydroelectric stations located across the island.

All the common shares of Newfoundland Power are owned by Fortis Inc. (NYSE/TSX: FTS), the largest investor-owned distribution utility in Canada, which serves approximately 3,200,000 gas and electric customers, with total assets of approximately $49 billion.

NEWFOUNDLAND AND LABRADOR HYDRO

Newfoundland & Labrador Hydro is a fully regulated, crown-owned electric utility that owns and operates facilities for the generation, transmission and distribution of electricity to utility, industrial and retail customers in the Province of Newfoundland and Labrador. At Hydro, we recognize a dependable source of electricity as an essential part of daily life, and have provided safe and reliable electricity for over 50 years.

Hydro has an installed generating capacity of 1,763 megawatts (MW) and generates and transmits over 80 per cent of the electricity consumed by Newfoundlanders and Labradorians every year. Hydro has locations throughout the province including nine hydroelectric generating stations, one oil-fired plant, four gas turbines, and 25 diesel plants. Hydro also maintains 54 high-voltage terminal stations, 25 lower-voltage interconnected distribution stations, and thousands of kilometers of transmission and distribution lines. Hydro has also recognized wind as a valuable energy source and has developed a strategy to leverage this source of clean, renewable energy.

Hydro is focused on long-term strategic planning to ensure a continued reliable source of electricity. Continuous infrastructure upgrades and use of new technology is one way we commit to providing excellent customer service. Hydro continues to search for the best way to provide power that is cost efficient, sustainable and environmentally sound.

OVERVIEW OF THE TAKECHARGE PARTNERSHIP

Since 2008, the Newfoundland Power and Newfoundland and Labrador Hydro have offered customer energy conservation information and programming on a joint and coordinated basis under the takeCHARGE energy conservation brand. The Utilities' provision of energy conservation programming is responsive to customer expectations, supports efforts to be responsible stewards of electrical energy resources and is consistent with provision of least cost, reliable electricity service.

STUDY CONTEXT

This potential study comes at a transitional time for Newfoundland and Labrador's electric utilities, stemming from changes to the province's generation and transmission systems. This is taking place against disruptions to North America's electricity utility industry as a whole, including a growing focus on customer needs and their opportunities to save energy, shift demand and switch fuels. These opportunities – driven by rapidly evolving technology, policies and consumer preferences – put more emphasis than ever on conservation and demand management opportunities that can help utilities balance supply and demand, considering both time and locational variations, to maintain electricity service reliability and affordability.

Changes to Newfoundland and Labrador's Energy Supply

This study provides a forecast of CDM Program potentials over the 2020-2034 period during which Newfoundland and Labrador's electricity system will undergo significant changes. Primary among these will be the Muskrat Falls hydro-electric generation facility which is expected to be fully commissioned by 2020. Other changes include the recent 900 MW expansion of the Labrador-Island link transmission system that will offset new industrial loads and retiring thermal generation facilities on the island. Finally, NL Hydro will soon be able to participate in local energy markets as it becomes interconnected to the North American grid.[6]

As a result of the combined impact of these changes, NL Hydro faces a challenge to maximize the value of energy exports and off-peak sales to mitigate customer rates, while reducing winter peak demand, particularly on the IIC system where winter peak marginal costs are particularly high. CDM offers an opportunity to reduce on-peak sales and peak demand in a cost-effective manner, thereby supporting NL Utilities' efforts to mitigate rates. Moreover, fuel switching to electric heating and electric vehicle adoption can further increase electricity usage,[7] but considerations must be made to ensure that electricity rates are managed to make these options attractive to customers, and that the new demand does not increase IIC winter peaks. This study provides insights into the potential for each of these opportunities considering the consumption and peak load impacts, as well as the cost-effectiveness to the Utilities and customers alike.

New Lighting Standards are Impacting Efficiency Program Focus

Across North America, changes to the standards for lighting are being closely watched by program administrators, as they will largely eliminate residential lighting savings opportunities, along with a significant portion of commercial sector lighting savings, when they come into force. Historically a significant contributor to portfolio savings, lighting is transforming, and electric efficiency programs may seek to invest CDM program budgets in new measures and program delivery strategies to achieve savings. Leveraging a strong foundation of

---

[6] MARGINAL COST STUDY UPDATE – 2018, Summary Report, NL Hydro, 2018.

[7] The net revenue gained from increased domestic sales can be used to offset the revenue that must be recovered to offset the costs of the Muskrat Falls project, thereby helping to mitigate customer rates.

Newfoundland and Labrador-specific market data, the potential study will be key in planning and optimizing the programs to do just that.

Electrification of Heating and Transportation

As the 2030 deadline for the first of Canada's commitments under the Paris Agreement on Climate Change approaches,[8] increasing attention is being paid to the emissions reduction potentials from electric vehicles and switching heating loads to electricity. When Muskrat Falls achieves full power, the province's generation mix will be 98% supplied by hydroelectricity, however, this may also bring increased customer electricity rates that may dissuade Newfoundland and Labrador homes and businesses from replacing oil heating with electric heat pumps or adopting electric vehicles. Moreover, the Provincial Government has put in place a carbon pricing plan that does not apply to home heating oil, and while it does apply an incremental new tax on gasoline and diesel for transportation, it also replaces an existing tax thereby reducing the carbon price impact to customers by nearly half.[9] While electric heating and EVs offer significant potential to reduce GHG emissions and increase domestic sales which will help offset the costs of Muskrat Falls, the current fuel pricing signals in the province may hinder the market for customers to adopt these clean energy technologies.

This study includes two chapters that forecast the expected baseline fuel switching and heat pump adoption rates, as well as the baseline adoption of EVs. The study also assesses the potential impact of utility incentives for purchasing electric heating equipment and vehicles, as well as options for investing in enabling strategies and infrastructure.

Demand and Load Management an Emerging Priority

As with many North American utilities, the NL Utilities are increasingly considering energy efficiency and demand response alongside supply-side resource options in addressing system capacity constraints. In particular, NL Utilities sees significant benefits from reducing winter peak loads in the IIC system. The achievable potential quantified in this study will help to support utility decision-makers in considering CDM as an option to address system constraints. Along with CDM programs, the study also forecasts heating fuel switching to electric heating and EV adoption that should be factored into system planning considerations. The projected impact of future codes and standards are also included in the study, to the extent possible considering uncertainties over future lighting standards in the USA, enforcement timelines, and acknowledging long-term changes in codes and standards which are unpredictable to a large extent.

The Need for Newfoundland and Labrador Specific Market Data

Because of these changing conditions, the need for leveraging a wide range of NL-specific sources and recently collected market data was crucial to ensure that the study was reflective of Newfoundland and Labrador's unique market and electric system conditions. This study therefore characterizes the energy-using technologies currently found in the Newfoundland and Labrador market, along with key features of the province's building stock. Leveraging the Utilities' recently conducted end-use surveys that capture Newfoundland and Labrador-

---

[8] Canada committed to a 30% reduction in GHG emissions relative to 2005, by 2030.

[9] Source: https://www.releases.gov.nl.ca/releases/2018/mae/1023n01.aspx.

specific market data, this study provides an assessment of attainable CDM opportunities. This information was supplemented with further primary data collection from 666 NL homes and 150 businesses to ascertain the barriers to adopting efficiency technologies and participating in CDM programs. Further verification was attained through 15 market actor interviews and residential and commercial stakeholder workshops to capture the perspectives of local players who are actively delivering efficiency technologies to NL homes and businesses. Moving forward, this study will be instrumental in the design of energy efficiency programs that are well-suited to the Newfoundland and Labrador context and will capture savings opportunities.

CDM POTENTIAL STUDY SCOPE

The Newfoundland and Labrador Conservation Potential Study (hereafter called "the Study") provides an assessment of CDM programs savings over a 15-year period, from 2020 to 2034, covering the three electricity systems in the province.

Island Interconnected (IIC) System: Refers to the combined service territories of NF Power and NL Hydro on the island of Newfoundland, including transmission level large industrial customers. The vast majority of electricity customers in NL are located on this system (95% of residential customers and 93% of Commercial and Industrial customers).

Labrador Interconnected (LAB) System: Refers to NL Hydro service territory in Labrador, including transmission level large industrial customers.

Isolated Diesel Generation (ISO) System: Refers to the collection of isolated diesel generators operated by NL Hydro in remote communities across the province.

Figure 1-1. NL Utility Service Territories

Where applicable, individual potential assessment models were created for each system to capture the unique opportunities. This included systems specific market data, avoided costs, customer rates, and energy measure characteristics.

The study assessed the changes in electricity consumption associated with the full range of commercially viable energy efficiency measures, as well as the potential impacts on electric peak demand, both from efficiency measures, and demand response initiatives. Increases in electricity consumption and demand were assessed from primary space and water heating fuel switching (from oil and wood to electricity), as well as electric vehicle adoption.[10]

The Study quantifies the electric system impacts associated with four streams of CDM programming, as laid out in **Table 1-1** below. For each study component, a separated modelling effort was undertaken to accurately

[10] These were treated as parallel studies, and the combined impact of CDM initiatives is presented separately from the fuel switching and electric vehicle adoption impacts in this report.

capture the key inputs and relationships that drive the adoption and impacts of efficiency measures, demand response programs, fuel switching and electric vehicles among the province's homes and businesses.

Table 1-1. CDM Programing Components Covered in the NL Conservation Study

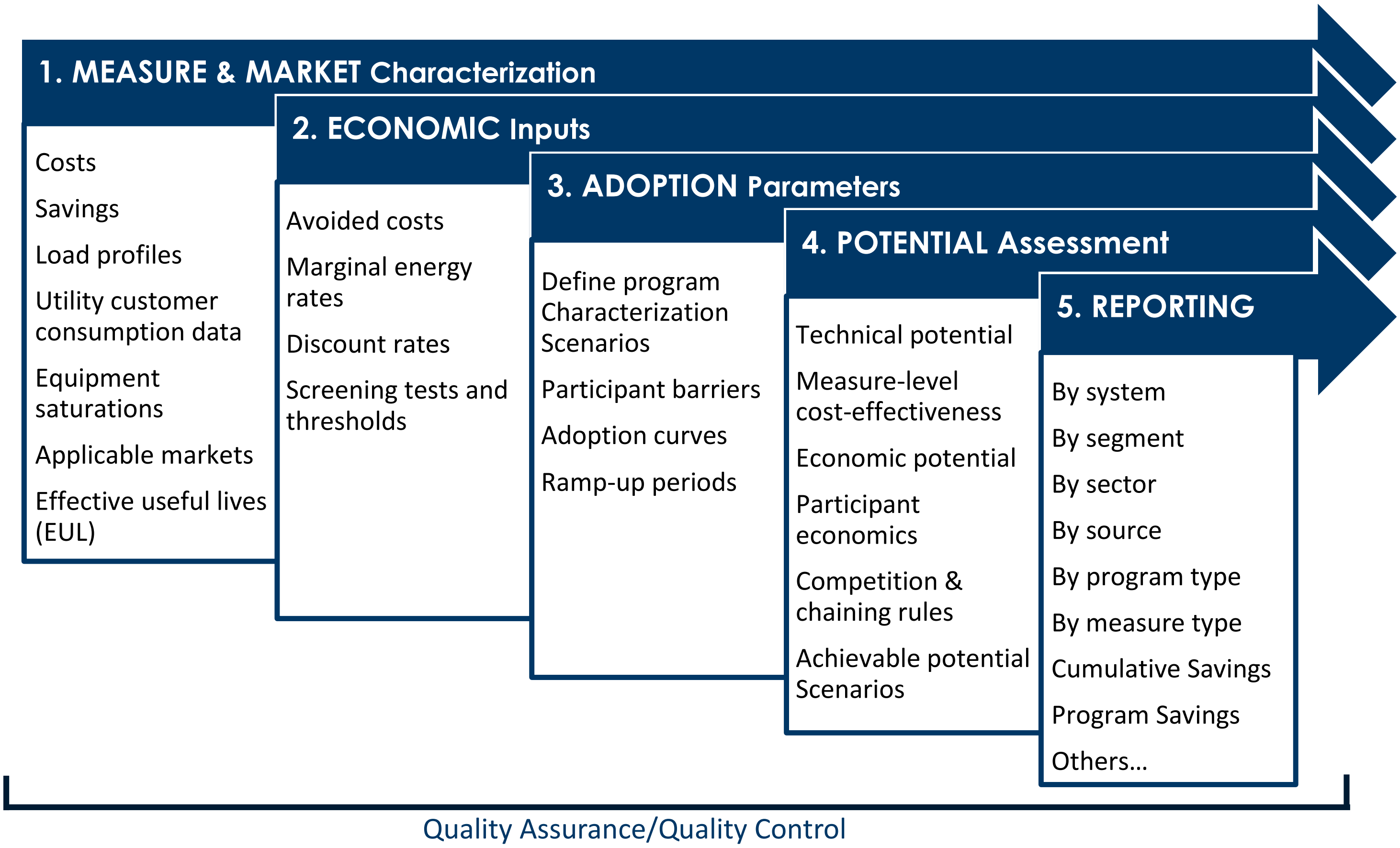
Study Component	Model Applied	Systems Studied	Details
Energy Efficiency	Dunsky's Energy Efficiency Potential (DEEP) Model	IIC, LAB, ISO	Appendix A
Demand Response[11]	Dunsky's Demand Response (DR) Model	IIC, LAB	Appendix B
Fuel Switching[12]	DEEP Model adapted for Heat Pump adoption	IIC	Appendix C
Electric Vehicles	Dunsky's Electric Vehicle Adoption Model	Province-wide	Appendix D

Using Dunsky Energy Consulting's various potential modelling tools, the study applied a granular, bottom-up modelling approach to define the energy savings opportunities for each savings stream, in each market sector based on equipment saturations developed through prior market data collected by the NL Utilities. The detailed methodology for assessing the potential for each savings stream is outlined in the Appendices found in Volume 2 of this report. The high-level study process flow is outlined below (**Figure 1-2**).

[11] Demand response programs were assessed only for the interconnected systems due to the limited applicability of active demand management in the small diesel generated systems that characterize the ISO.

[12] The fuel switching analysis focuses on the projected uptake of heat pumps to replace oil, wood or electric resistance as the primary space and water heating source in the province's homes and businesses. The Fuel Switching study focused on the IIC system as the opportunities for heat pump adoption in the other systems are minimal.

Figure 1-2. Potential Study Modelling Process Flow



USES FOR THIS POTENTIAL STUDY

This potential study is a high-level assessment of electricity impacting opportunities in the Province of Newfoundland and Labrador over the next 15 years. Its main purposes are to support:

- **Resource planning:** Evaluate the impact of Energy Efficiency, Demand Response, Fuel Switching and Codes & Standards on long-term energy consumption and demand needs at the grid/distribution level.
- **Efficiency program planning:** Assess achievable CDM opportunities to improve CDM program planning and help meet long-term savings objectives, and determine which sectors, end-uses and measures hold the most potential.

This potential study is *not* intended to give granular information about measures in specific segments, but rather give a macro view of efficiency potential. Moreover, it is not a program design document that accurately forecast savings achieved through Utility programs in a given future year, but rather quantify the total potential opportunities that exist under specific parameters.

DATA SOURCES AND USES IN STUDY

The CDM Potential Study leveraged a pool of NL-specific data to prepare potential models that are representative of each electricity system. This was supplemented with primary research through phone and web surveys with NL businesses and homeowners to collect further details related to their buildings and the barriers they face in adopting energy efficiency measures or joining DR programs. **Table 1-2** provides an overview of the key data sources used in the study, and a more detailed description of the sources, inputs and assumptions can be found in Appendix E.

Table 1-2. Newfoundland and Labrador Specific Data Sources used in the Conservation Potential Study

Data source	Application in study
Utility Customer data	The utilities provided historical electricity consumption data and customer counts for each market segment. These were used to fix total consumption and number of customers in each market segment.
End-Use surveys	A Commercial End-Use Survey (CEUS) and a Residential End-Use Survey (REUS) were conducted by the utilities in 2018 and 2017 respectively. These results were applied to establish equipment saturations in the model.
Economic data	Customer rates, avoided costs and discount rates were used to calculate TRC, PACT and PCT benefits.
CDM program data	Program evaluation reports and CDM plans were provided by the Utilities. These were used to characterize CDM programs for model (incentive level, administration costs), and benchmark model findings.
Baseline EV adoption projection	Used to define market for EV smart charging DR measure.
2015 CDM Potential Study[13]	Used to supplement market and measure characterization data for the model where there are gaps in the Dunsky measure database and/or the end use survey data.
Historical utility load curve	Hourly system load curves for IIC and LAB were used to establish DR addressable peak and define standard peak day.

[13] Reference: Newfoundland and Labrador Conservation and Demand Management Potential Study: 2015, ICF International.

Consumption and demand forecasts	Used to assess % savings in each period of the study and determine DR addressable peak forecast.

MARKET SEGMENTATION

Based on the review of NL Utilities' customer data and discussions with the utilities, Dunsky divided the customer bases into the market sectors and segments as presented below (**Table 1-3**). Overall, the study assesses both residential and commercial sectors, with specific considerations for a range of segments within each, including single detached, attached and apartments in the residential sector, and twelve commercial segments such as offices, grocery stores and restaurants, industrial, and others. Developing results for each segment, the study modeled the cumulative savings over the 2020-2034 period to arrive at the assessment of the technical, economic and achievable potentials.

Table 1-3. Sectors and Segments Included in the Study (Both Utilities Combined)

Sector	Segment	Customers	2018 Consumption (MWh)
Residential	Single Detached	191,338	3,362,706
	Attached	29,345	466,251
	Apartments	30,071	290,509
Commercial	Office	5,495	464,442
	Retail	3,321	260,363
	Grocery/Restaurant	1,904	271,514
	Health Services	820	179,979
	Education	738	312,206
	Warehouse	653	78,467
	Lodging/Hospitality	1,440	105,196
	Other Commercial	7,058	462,767
Industrial	Fishing	626	115,718
	Manufacturing	1,216	141,986
	Sm./Med. Industrial	4,781	312,330
	Large Industrial	6	3,628,000[14]

[14] Large Industrial annual consumption in the IIC system is projected to drop from 1,479 GWh in 2018, to 613 GWh by 2020 as transmission level customers increase self-generation.

Top-Down Assessment of Large Industrial Customers (Transmission-Level)

The Large Industrial Segment did not lend itself to the bottom-up adoption modelling approach applied for the other segments as it has such a small number of customers and no CEUS data was available to determine the saturation of specific equipment in each facility. For this segment the study applies a top-down approach to assess the potential efficiency and peak demand savings based on the best available projections from past studies and current curtailment contracts. An outline of the efficiency modelling approach applied for this segment can be found in Appendix E.

CUSTOMER BARRIERS SURVEY AND ADOPTION BARRIER-LEVEL SETTING

To support the application of adoption curves in the Potential Model, two barriers surveys were conducted as part of the study:

Residential Web Survey: Using email addresses associated with residential customers, a web survey (666 completes) was conducted. Results were stratified by building type. The survey covered barriers to adopting the following categories of energy efficiency measures:

- Insulation
- Air sealing
- Heating systems
- Heat pumps
- Appliances
- Smart thermostats

In addition, the survey assessed residential customer considerations to participating in demand response/demand control and fuel switching initiatives.

Commercial Telephone Survey: 150 Commercial customers completed a 15-minute telephone survey. Results were stratified by each of the eight commercial segments, as well as the fishing and manufacturing industrial segments.

Each survey included a series of questions pertaining to decision-making factors and barriers faced by customers when they consider adopting energy efficiency measures. The survey captured responses from each of the customer segments, and differentiated responses for the following six major end-uses:

- Lighting
- HVAC
- Commercial refrigeration equipment
- Commercial kitchen equipment
- Water heating equipment
- Motors and compressed air systems

The survey also asked respondents about the financial factors they consider when purchasing or replacing energy-using equipment, and how varying levels of incentives may influence their purchasing decisions. The survey results were treated to establish a baseline barrier level for each market segment / end-use combination. These were then mapped to each measure in the model, adjusting for measure-specific factors, such as installation complexity or time in the market. Finally, the barrier analysis applied system-wide barrier increases for the LAB and ISO systems to account for the additional barriers faced in the province's remote communities. These were then used as inputs to the Potential Model which determined which adoption curve is applied to each measure-market segment combination. Further details on the barrier survey and the barrier level setting can be found in Appendix E.

MEASURE CHARACTERIZATION

Comprehensive lists of efficiency and demand response measures applicable to each market sector were provided to the NL Utilities early in the project for approval. These lists were expanded and adapted based on feedback from the NL Utilities, and the final approved measure list was compiled. Further details on the measures applied in the study can be found in Appendix F.

Basic assumptions related to energy savings or impact factors were characterized for each measure using published Technical Reference Manuals (TRMs) from NL and other relevant jurisdictions, NL Utility program evaluation measure savings findings, NL climate data to determine effective full load heating and cooling hours, and other public and in-house data sources. The detailed measure lists and sources used for input characterization can be found in Appendix E. Measure details characterized for model inputs include:

- **Annual gross savings:** Per-unit electric savings are included, including consumption and demand values.
- **Incremental costs:** The incremental installed cost of the efficient technology as compared to the baseline option.
- **Load factors:** This category addresses summer and winter peak coincidence factors, seasonal savings distributions, as well as monthly peak load impacts for commercial customers.
- **Measure life:** This category addresses the EUL of each measure and baseline technology.
- **Installation Schedule:** For each measure the study determines the installation timing relative to the EUL of the existing equipment, and its attribute as either replacing existing equipment, or being a newly added piece of equipment.

Treatment of EISA 2020 Standards for Lighting in this Study

Phase two of the Energy Independence and Security Act (EISA) is scheduled to come into effect in the United States on January 1, 2020, restricting the sale and manufacture of light bulbs that do not meet new minimum energy performance standards for bulb types covered by the regulations. These requirements are also anticipated to impact the Canadian market, as the Canadian government has indicated commitments to align efficiency standards with the U.S. By increasing baseline energy performance requirements, the new standards will reduce the savings that can be claimed by lighting efficiency programs.

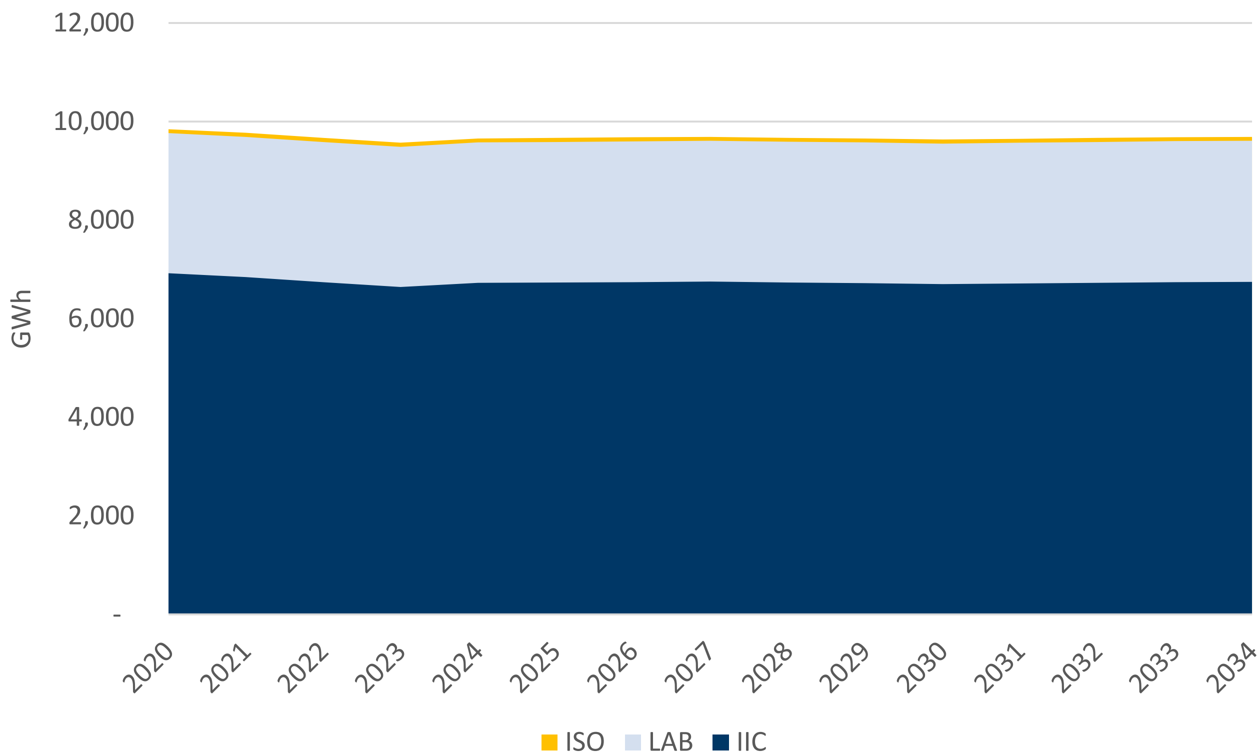
Informed by the timeline of previous amendments to the Canadian Energy Efficiency Regulations, the study assumes that the new lighting standards will be enforced in Canada beginning January 1, 2022 for standard screw-in type bulbs (referred to as A-Lamps in this study). The study applies an additional year of savings to be counted beyond the date of enforcement, assuming that stocks of incandescent and halogen bulbs will take approximately one year to deplete, and therefore will be available for sale until the end of 2022. Starting January 1, 2023, savings from the purchase of new bulbs covered by the regulation are no longer counted towards programs in the model.

On February 6, 2019, the US Department of Energy (DOE) announced plans to withdraw the expansion of energy efficiency standards for specialty lamps (referred to as Reflectors in this study). To account for this uncertainty, the study assumes that the market for specialty lamps will transform either through a change in standards or through a shift driven by manufacturers by 2025. As a result, the study does not apply any specialty lamp savings starting January 1, 2025.

NEWFOUNDLAND AND LABRADOR ENERGY USE BASELINE

Establishing the baseline energy consumption over the study period provides a valuable benchmark to the savings potentials in the study and facilitates an assessment of the impact that CDM programs can have on energy sales in the province. Baseline electricity use was provided by NL Utilities, and the values were then adjusted by Dunsky to remove the projected impact of efficiency programs post-2020 and included the impact of expected codes and standards changes. Below, the forecasted energy use in Newfoundland and Labrador is presented by sector and energy type for the years 2020-2034.

Figure 1-3. Forecasted Newfoundland and Labrador Energy Use Baseline for 2020-2034



Overall the sales projections indicate that annual consumption is expected to drop in the initial years then remain steady in the IIC system. This is due primarily to customer price sensitivity to the anticipated potential rate increases associated with the commissioning of the Muskrat Falls Project. For the LAB and ISO systems, the sales are expected to remain steady over the study period. Demographic data provided by the Utilities indicates the population in NL is expected to somewhat decline in the coming years. Moreover, expected changes to lighting standards leading to the transformation of standard and specialty bulbs in the early 2020s is expected to further contribute to a slight reduction in the forecasted baseline energy consumption, even before energy efficiency programs are considered.

Figure 1-4 and **Figure 1-5** present the breakdown of energy consumption in each of the three systems by sector and by end-use respectively. From these it can be seen that the IIC and ISO systems are dominated by residential and commercial consumption, while the LAB system is dominated by industrial consumption.

Figure 1-4. Newfoundland and Labrador 2018 Energy End-Use Breakdown by Sector – All Systems (GWh)

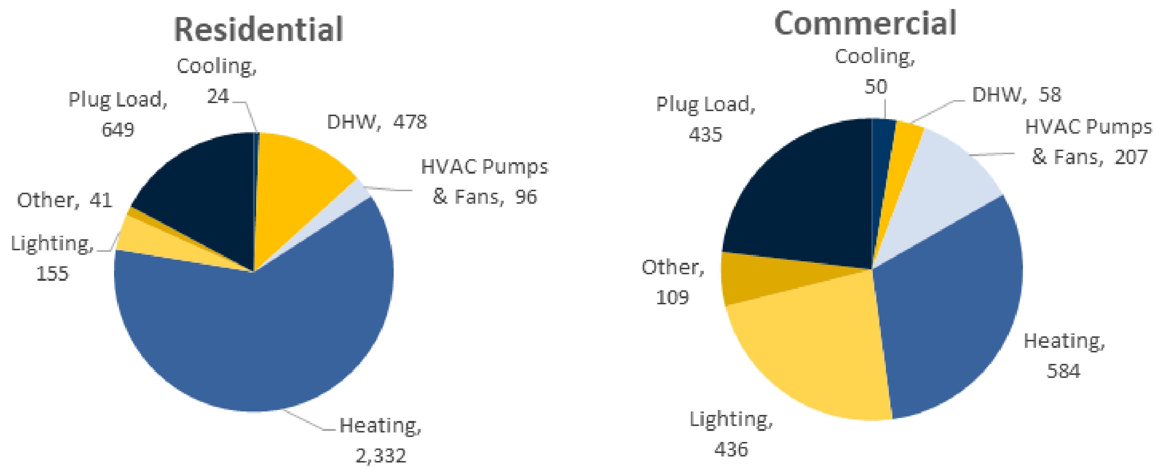
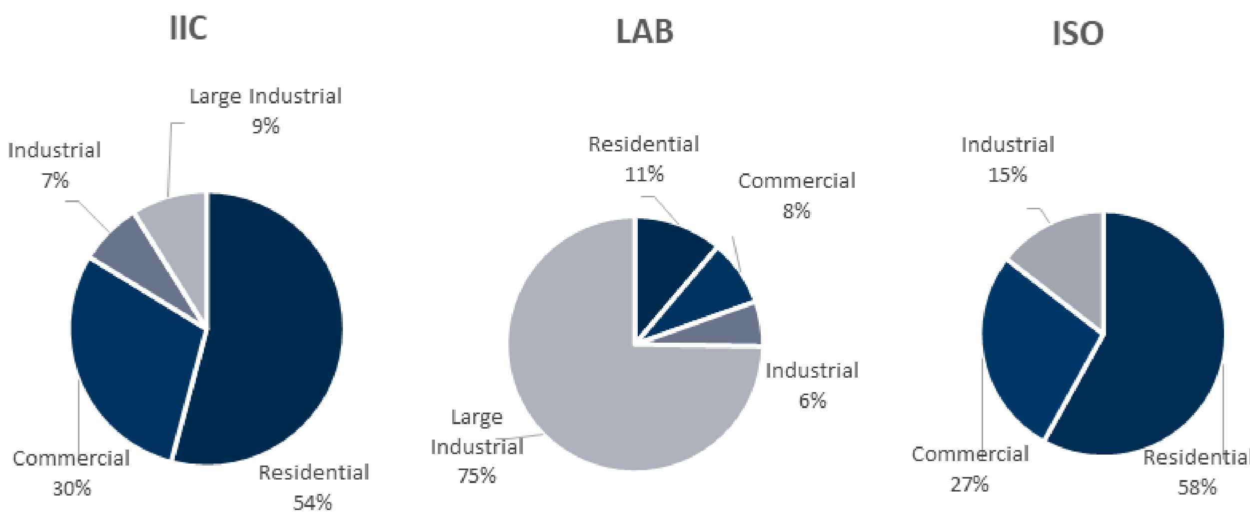


Figure 1-5. Newfoundland and Labrador Projected Energy Use Breakdown by Sector 2020

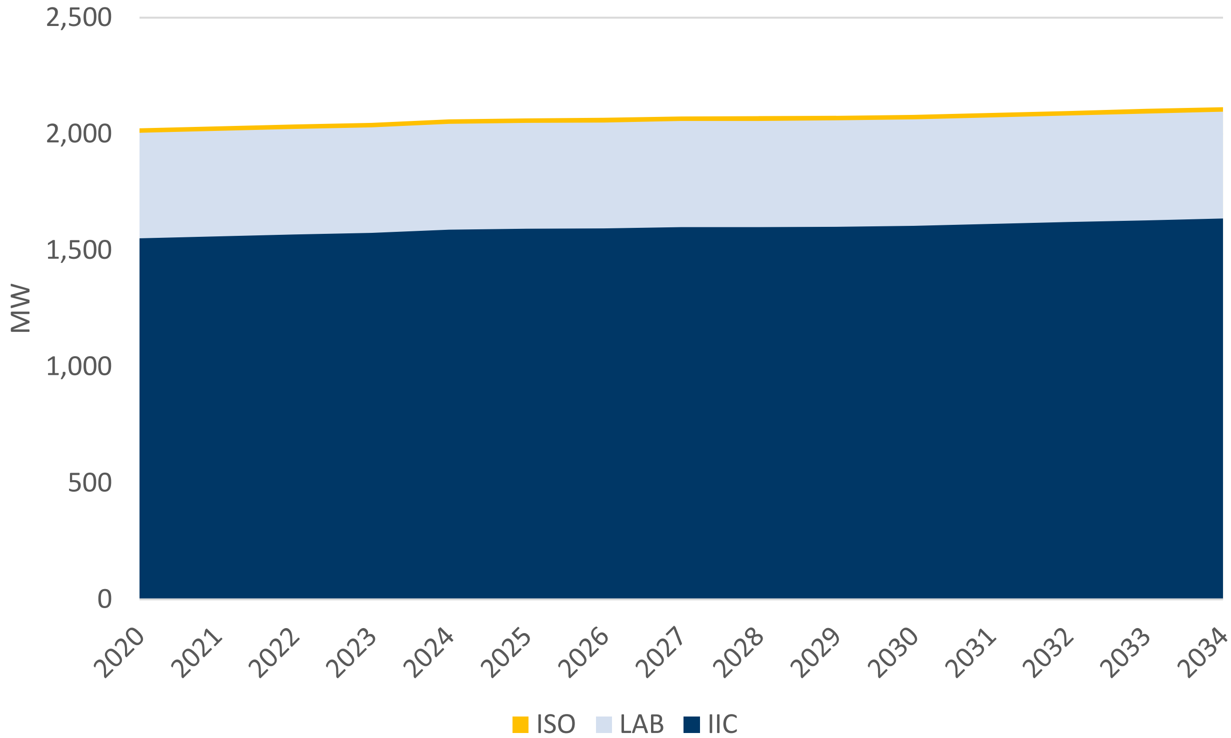


Note: Large Industrial refers to transmission-level industrial customers.

Based on the end-use breakdowns, it can be seen that residential heating dominates among all non-industrial loads, representing 23% of the overall province-wide electrical consumption load. By comparison, all industrial sector facilities together represent just 33% of the province-wide annual consumption. Plug load and lighting represent the next two largest non-industrial loads, representing 12% and 6% of the overall province-wide annual consumption respectively.

Figure 1-6 below provides the baseline demand projections for the three systems. Over the study period there is an expected steady rise in the IIC system annual peak demand, which is an opposite trend to the consumption projections provided above. Given the high avoided costs of capacity for the IIC system, this indicates that measures and programs that can mitigate demand increases may offer particular value in the CDM program portfolio.

Figure 1-6. Forecast Newfoundland and Labrador Annual Peak Demand by System



CDM PROGRAM SCENARIOS

As is standard practice in potential studies, the study assesses electric efficiency savings potentials at the technical, economic and achievable levels. For the achievable potential, which is the primary focus of the analysis, the study assesses savings resulting from potential program scenarios in order to determine how various levels of CDM investment and programming approaches can impact the achieved savings (see **Figure 1-7** below).

Figure 1-7. CDM Program Scenarios Used to Assess Achievable Savings

Lower	• **Lower Achievable Potential** Applies current Utility CDM program incentive levels and enabling activities, but includes the full range of cost-effective technologies, and disregards any budget constraints.
Mid	• **Mid-Range Achievable Potential** Applies increased incentive levels to reflect increased investments in CDM programs compared to the current portfolio.
Upper	• **Upper Achievable Potential** Applies increased incentive levels, and includes further investments in enabling activities to address customer barriers to adoption.

The Lower scenario indicates the level of savings that may be reached with current programs including additional technologies and if no budget limitations were applied.[15] The Mid scenario indicates how much additional savings could be achieved by increasing incentives and expanding programs to include new construction (NC), appliance recycling, and incentives to encourage customers to purchase higher efficiency cold-climate heat pumps. Finally, the Upper scenario provides an assessment of the combined impact of the increased incentive levels applied in the Mid scenario, along with further investments in enabling strategies to lower barriers to adoption (such as contractor training, consumer education or midstream initiatives).[16] These scenarios provide hypothetical impacts of high-level CDM program features. Developing detailed program designs including specific annual budgets and administration costs are beyond the scope of this study.

[15] New measures, not currently offered in the CDM programs, include commercial building insulation measures, some new lighting types (such as pole mounted LEDs), cooling equipment and chillers, retro-commissioning, compressor efficiency measures, and a range of residential appliances and envelope measures. A full list of all measures considered in the study, along with which would be new to the CDM programs can be found in Appendix E.

[16] Midstream refers to offering incentives to contractors or suppliers, rather than customers.

Enabling Strategies: Options for Reducing Customer Barriers

To optimize achievable potential savings, programs must go beyond incentives to address other non-economic barriers to customer participation. Barrier reductions can be achieved through enabling activities such as consumer education, contractor training and support, market research, program design and enhancements, marketing strategies, program evaluation (which can identify barriers to participation), and others.
(See Appendix A for a description of how Adoption Curves and Barriers are applied in this study).

The program scenarios assessed in this study capture the impact of current enabling strategies applied by the NL Utilities by calibrating the Lower program scenario achievable potentials to current CDM portfolio savings. The potential impact of investing further in enabling strategies is assessed under the Upper program scenario, where a half step reduction in barrier levels is applied over and above the Mid program scenario. While the potential study does not identify the specific enabling strategies engaged or the associated barriers addressed, the results are intended to provide a quantitative assessment of additional savings that can be unlocked through enabling strategies.

From there, program design analysis can be applied along with the Barrier Survey results from this study, to identify specific actions that would be appropriate for each measure and market segment.

CUMULATIVE AND PROGRAM EFFICIENCY SAVINGS

Study results are presented in two different ways, each serving a specific purpose and providing a different insight into potential savings.

Cumulative savings are covered in Chapter 2 and provide a rolling sum of all new savings that will affect energy sales. Cumulative savings provide the total expected impact on utility sales in each electricity system and should be used to determine the impact of CDM programs on long-term energy consumption and peak demand at the grid/distribution level.

Program savings are presented in Chapter 3 and provide the level of savings from measures that are incentivized through programs in a given year. Program savings should be used to assess achievable CDM program opportunities to improve CDM program planning and help meet short and long-term savings objectives and determine which sectors, end-uses and measures hold the most potential.

DEMAND RESPONSE PROGRAM SCENARIOS

The study includes an assessment of the technical, economic and achievable potentials of a wide range of demand response (DR) measures, and the results are presented for each set of measures under the achievable potential scenario results. It should be noted that aggregate results for the technical and economic potentials of all DR measures are not presented in this report. The study includes assessments of the technical and economic potential for each individual measure however, these are not considered additive due to the high degree of interaction among programs and the utility load curve. Measure-level Technical and Economic potential details are provided on a measure-by-measure level in Appendix F.

Furthermore, because the mix of DR programs has more of an impact than the incentive levels applied (provided that base case incentive levels are set high enough to attract a sufficient pool of participants), the study presents scenarios based on program mixes and approaches as outlined in **Figure 1-8** below. Because the interactions among programs and the utility load curve are complex and unpredictable before running the DR model, it is only apparent after the scenarios have been analysed which provides higher or lower DR potentials, and thus the scenarios are described by the program mix they contain, rather than their expected level of impact.

Figure 1-8. Demand Response Program Scenarios

Scenario 1

- **Enhanced Current DR Potential**
  The first scenario focuses on maximizing the impact from current DR programs (i.e. curtailment) and adding further programs that have little or no interactive effects with existing programs.

Scenario 2

- **Rate-Based DR Expansion**
  The second scenario approach focuses on the DR potential possible via rate-based measures such as Time of Use rates and/or Critical Peak Pricing. These are applied alongside existing curtailment programs.

Scenario 3

- **Equipment Control DR Expansion**
  The third scenario focuses on an equipment control approach, either through utility direct load control, or manual control of equipment. These are applied alongside existing curtailment programs.

COST AND RATE SENSITIVITY

The Newfoundland and Labrador CDM Potential study covers a 15-year study period, during which electricity rates, avoided costs and carbon pricing in the province are subject to notable uncertainty. To capture the impact that changes in these factors could have on the market adoption of the studied technologies, sensitivity analysis was conducted covering these three key economic factors. **Table 1-4** provides a guide to the sensitivity ranges applied in the study and the base case values applied throughout the presentation of results. Detailed electricity rates and carbon pricing tables are provided in Appendix E.

Table 1-4. Rate, Cost and Price Sensitivity Ranges Applied in the Potential Study

	LOW	MID	HIGH
Electricity Rates: Electricity rate scenarios were provided by the utilities based on likely mitigated or unmitigated rate scenarios that account for the rate impacts from the Muskrat Fall generation facility.	Mitigated rates that exhibit little or no increase as compared to current rates when adjusted for inflation.	Mid-point between mitigated and unmitigated rates.	Unmitigated rate projections wherein the Muskrat Falls financing costs will be recovered through customer rate increases.[17]
Avoided Costs: Current and projected avoided costs of peak capacity in NL are high compared to neighbouring provinces and may be subject to revision. As such the Utilities provided avoided cost scenarios to test the impact of lower avoided costs.	60% of currently projected avoided capacity costs.	80% of currently projected avoided capacity costs.	Currently projected avoided cost for IIC provided by the Utilities. LAB avoided costs of capacity set to 90% of IIC avoided costs.
Carbon Pricing: The Provincial Government's carbon pricing plan has been accepted by the Federal Government, but future evolutions in GHG emissions policy could lead to an increase in carbon pricing on heating oil and transportation fuels.	Current NL Carbon Pricing Plan. No carbon price on heating oil, and a 9.79% carbon tax on gasoline and diesel.	Federal Government Backstop Carbon Pricing starting at $20 per tonne in 2019 and rising $10 per year to $50 per tonne in 2022.[18]	The social cost of carbon is a monetary measure of the climate change impact from emitting an additional tonne of carbon dioxide (CO_2). [19]

Note: Light-blue shaded cells indicate the base-case for each sensitivity factor.

---

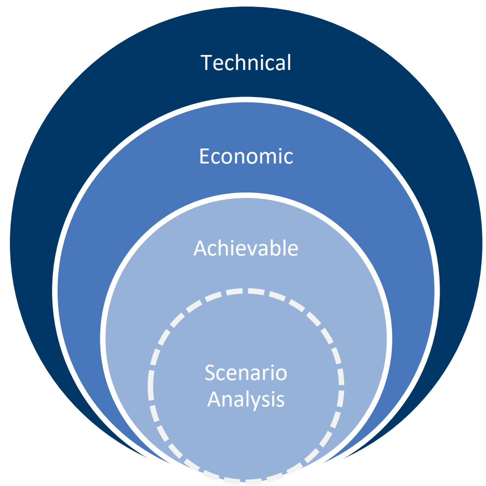
[17] Methodology Review Report, the estimated residential rate is projected to be approximately 21¢ per kWh without additional rate mitigation beyond Hydro's forecast export revenues.

[18] Source: Government of Canada, Technical Paper on the Federal Carbon Pricing Backstop, https://www.canada.ca/content/dam/eccc/documents/pdf/20170518-2-en.pdf.

[19] Source: Government of Canada, Technical Update to Environment and Climate Change Canada's Social Cost of Greenhouse Gas Estimates, https://ec.gc.ca/cc/default.asp?lang=En&n=BE705779-1.

2. CUMULATIVE EFFICIENCY SAVINGS POTENTIAL

The following graphs and tables present Newfoundland and Labrador's cumulative savings potentials, covering energy (GWh) and peak demand (MW) as applicable. The results cover the annual cumulative impact on sales in each of the three studied electricity systems: IIC, LAB and ISO. The following sections present the savings potentials at three levels, as described below:



Technical potential: The theoretical maximum savings potential, ignoring constraints such as cost-effectiveness and market barriers.

Economic potential: The savings opportunities available should customers adopt all cost-effective savings, as established by screening measures against the Total Resource Cost (TRC) test.[20]

Achievable potential: The savings from cost-effective opportunities once market barriers have been applied, resulting in an estimate of savings that can be achieved through CDM programs. Three achievable potential scenarios were modeled to examine how varying factors such as incentive levels and market barrier reductions impact uptake:

- **Lower:** Applies current Utility CDM program incentive levels and enabling activities, including an expanded range of cost-effective technologies and without any program budget constraints.
- **Mid-range:** Applies increased incentive levels to reflect increased investments in CDM programs compared to the current portfolio. Also adds new construction, appliance recycling, and heat pump programs.
- **Upper:** Applies same increased incentive levels as in the Mid scenario, but with further investments in enabling activities to address customer barriers to adoption.

Throughout the following presentation of results and analysis, the reader should be aware of the following:

- **Achievable potential is presented under the Mid scenario**, except where otherwise specified.
- **All savings are expressed in at-the-meter terms**, rather than at-the-generator terms. The savings results therefore do not include line-losses in the transmission and distribution network. Line losses are added

[20] As is standard practice in potential studies, the TRC calculation applied to assess the Economic screening considers the costs and benefits of each measure, but does not include program costs such as administration or start-up costs. In this study, efficiency measures with a TRC of 0.8 or higher were retained in the Economic Potential.

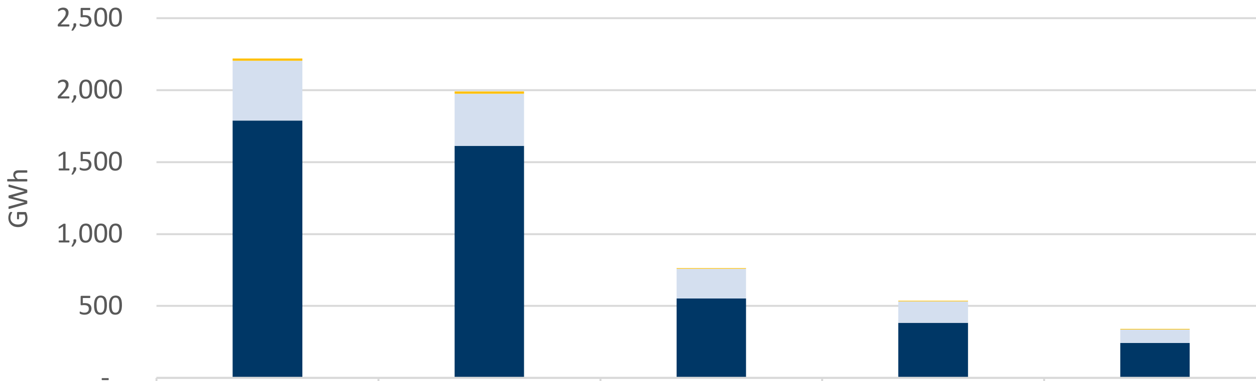
to the at-the-meter savings to calculate at-the-generator savings (to reflect the true avoided costs of generation) and these are used in the TRC calculations.

- **All savings are calculated under the Mid customer rates scenario:** Unless otherwise stated, the results in this section were generated using the mid customer rates scenario that assumes a mid-point in the rates between the mitigated and unmitigated rate projections. Details on the customer rates are provided in Appendix E.

ELECTRIC ENERGY SAVINGS POTENTIAL

Below, the technical, economic, and achievable savings are presented side-by-side for electric potential savings (**Figure 2-1** and **Table 2-1**) for each system over the study period (2020-2034).

Figure 2-1. Cumulative Electric Potential Savings from Efficiency Under Mid Rates (2034)



	Technical	Economic	Upper	Mid	Lower
ISO	16	16	6	5	4
LAB	415	363	207	149	94
IIC	1,788	1,613	552	384	242

Table 2-1. Cumulative Potential as a Portion of Sales (2034)

Study Component	Economic Potential	Lower	Mid	Upper
IIC	24%	3.6%	5.7%	8.2%
LAB	13%	3.3%	5.2%	7.2%
ISO	19%	5.4%	5.8%	6.8%
Total (Province-wide)	21%	3.5%	5.5%	7.9%

From these results, the following observations can be made:

- **Technical and economic potential are close in magnitude.** More than 95% of the technical potential is considered cost-effective. This is a consequence of three factors:
    - The avoided costs of generation for the IIC and LAB system are extremely high ($420/kW and higher). Thus, measures that offer significant peak savings impacts can quickly become cost-effective as they accrue peak savings benefits.

- As per the Utilities instruction, the study applied a TRC screen of 0.8, meaning that all measures whose lifetime benefits are equal to or higher than 80% of the lifetime costs are included in the economic potential. This allows for marginally cost-effective measures to be combined with other more cost-effective measures to be considered for inclusion in the CDM programs, as long as the overall program or portfolio can achieve a TRC of 1.0 or higher. Some measures may not be able to be combined cost effectively therefore reducing the total achievable potential that is shown in this report.
- Finally, measures that are currently not commercially available, and are not expected to become available within next 15 years, were excluded from the measure list.[21] This reduces the technical potential but has no impact on the economic or achievable potential scenario outcomes.

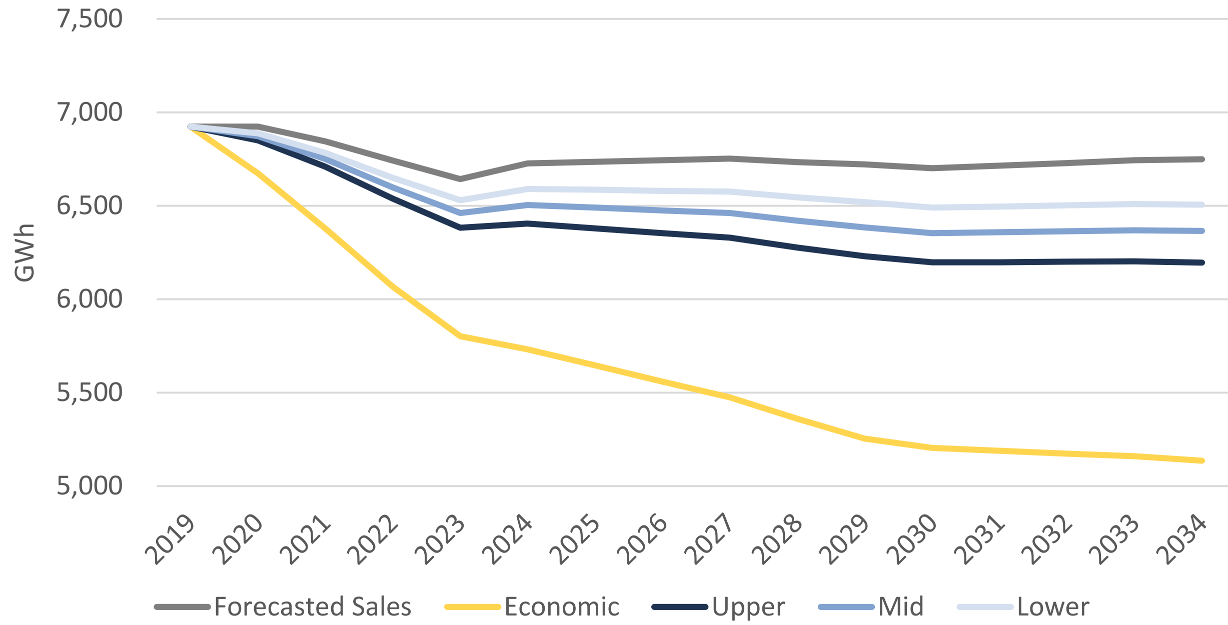
- **The achievable potential scenarios are all significantly lower than the economic potential.** This is largely attributed to market barriers such as customer knowledge, technology availability, the perceived higher cost of energy efficient equipment and uncertainty about the savings from efficiency improvements.
- **Investing in barrier reductions can increase achievable potential over and above raising incentives alone.** The combination of increased incentive levels and enabling strategies that can reduce customer barriers, as applied under the Upper program scenario more than doubles the incremental savings increase over the Lower program scenario.

IMPACT ON ELECTRICITY SALES

The graphs below illustrate the impact on annual savings under each achievable program scenario and the economic potential for each system (**Figure 2-2** to **Figure 2-4**). In each case it can be seen that the reduction in sales is steepest in the initial five years while lighting savings continue, and new programs and new measures ramp up. In the later years, the projected impact on savings flattens as the new equipment standards take hold for lighting and heat-pumps and the number of available opportunities for replace-on-burnout measures (replacement of a piece of equipment that has reached the end of its useful life with a more efficient option) go down until the market is depleted. Subsequent equipment replacements thereby are counted as re-participation and are not included as additional cumulative savings.

[21] The commercial availability and viability of measures was assessed through the market actor interviews, and a review of available secondary sources such as technical reference manuals, as well as Dunsky's professional judgment. A list of considered measures that were not retained for inclusion in the model is provided in Appendix E.

Figure 2-2. Cumulative Electric Potential: Mid Scenario Impact on Sales Under Mid-Rates (IIC)



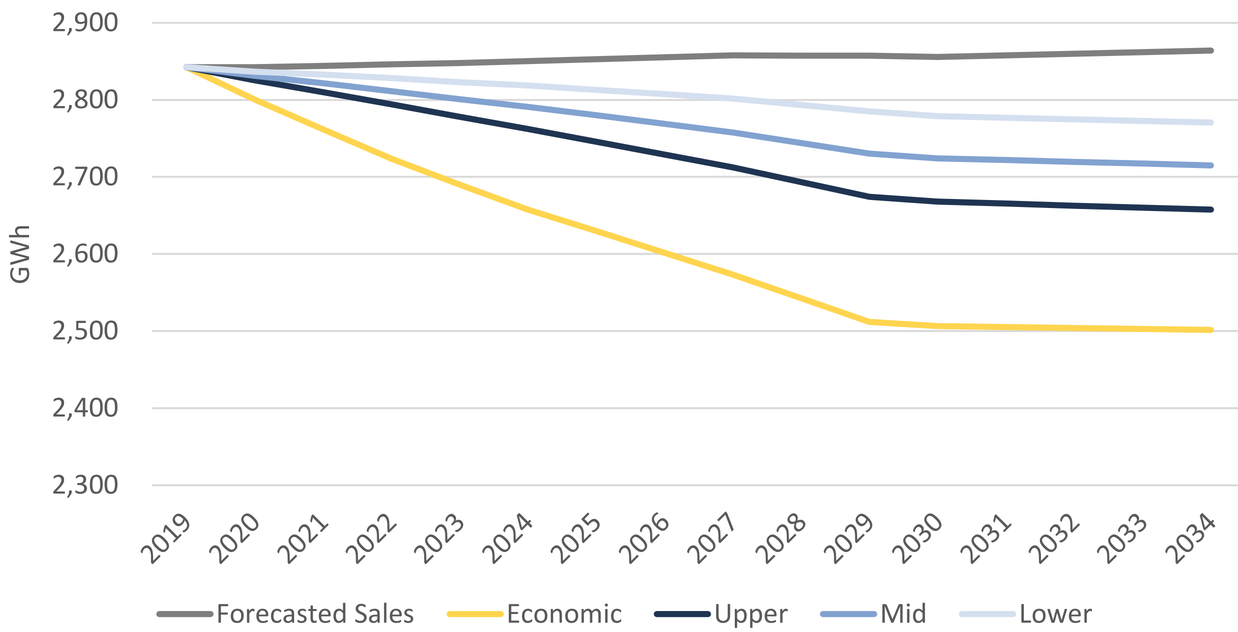
Note: Y axis does not start at zero in order to show trends more clearly.

The potential impact on electricity sales in the IIC system reveals the following:

- **Economic Potential:** Savings from economically viable measures could reduce sales by as much as 24% over the study period. This is mostly accomplished in the first 10 years, after which programs would maintain slightly decreasing annual sales.

- **Achievable Potential:** Savings from the program scenarios can achieve up to an 8.2% reduction in sales by 2034 under the Upper scenario, or a 3.6% reduction in sales by 2034 under the Lower program scenario.

Figure 2-3. Cumulative Electric Potential: Mid Scenario Impact on Sales Under Mid Rates (LAB)

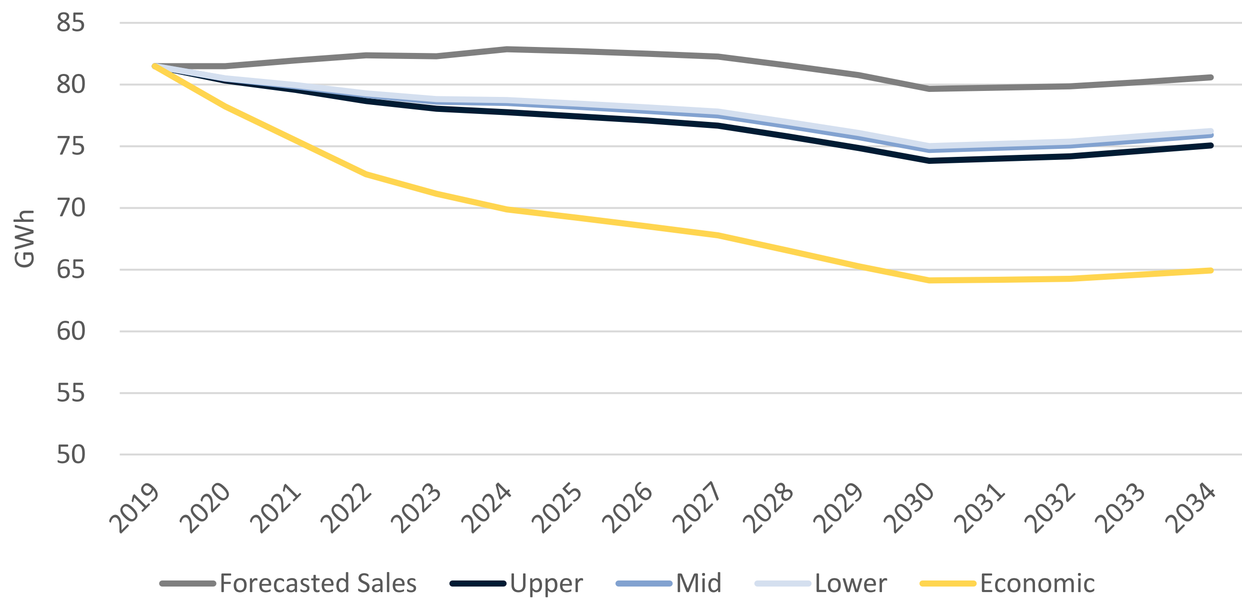


Note: Y axis does not start at zero in order to show trends more clearly.

The potential impact on electricity sales in the LAB system reveals the following:

- **Economic Potential:** Savings from economically viable measures could reduce sales by as much as 13% by the end of the study period. This is largely accomplished in the first 10 years, after which programs would maintain slightly decreasing annual sales.
- **Achievable Potential:** Savings from the program scenarios can achieve up to a 7.2% reduction in sales by 2034 under the Upper scenario, or a 3.3% reduction in sales by 2034 under the Lower program scenario. Similar to the economic potential, these impacts are largely accomplished in the first 10 years, after which the programs would maintain savings levels through re-participation. In all achievable program scenarios, any growth in projected sales in the LAB system may be offset by efficiency savings.

Figure 2-4. Cumulative Electric Potential: Mid Scenario Impact on Sales Under Mid Rates (ISO)



Note: Y axis does not start at zero in order to show trends more clearly.

The potential impact on electricity sales in the ISO system reveals the following

- **Economic Potential:** Savings from economically viable measures could reduce sales by as much as 19% by the end of the study period. This is largely accomplished in the first five years, after which programs would maintain slightly decreasing annual sales.
- **Achievable Potential:** Savings from the program scenarios can achieve up to a 6.8% reduction in sales by 2034 under the Upper scenario, or a 5.4% reduction in sales by 2034 under the Lower program scenario. Similar to the economic potential, these impacts are largely accomplished in the first five years, after which the programs would maintain savings levels through re-participation. Moreover, the spread among the program scenarios is small compared to the IIC and LAB systems. This is due to the current ISO system programs that offer high incentives and apply enabling strategies such as direct install for residential programs which leaves little room for increasing savings through raised incentives in the residential sector.

SAVINGS POTENTIAL BY SECTOR AND SEGMENT

Below, cumulative savings under the Mid program scenario are presented by system, sector and time period (**Figure 2-5** and **Figure 2-6**). The results presented focus on the Mid program scenario for illustrative purposes, as the proportional amount of savings in each sector are generally consistent under each of the program scenarios. For further details, tables of cumulative savings by sector and end-use can be found in Appendix F for all program scenarios.

Figure 2-5. Province-Wide Cumulative Achievable Potential (GWh) by sector: Mid Program Scenario Under Mid Rates

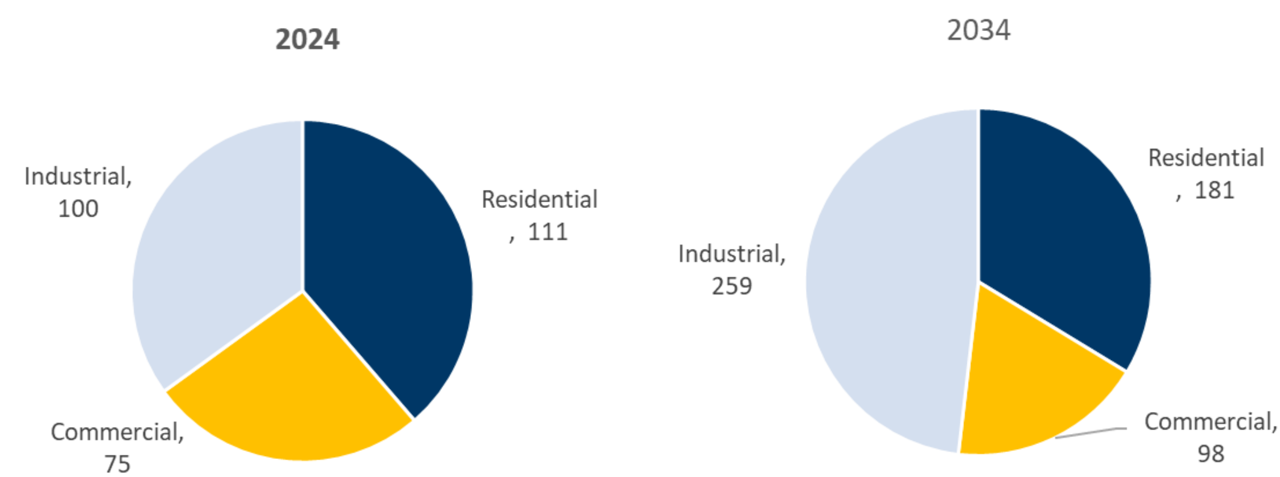
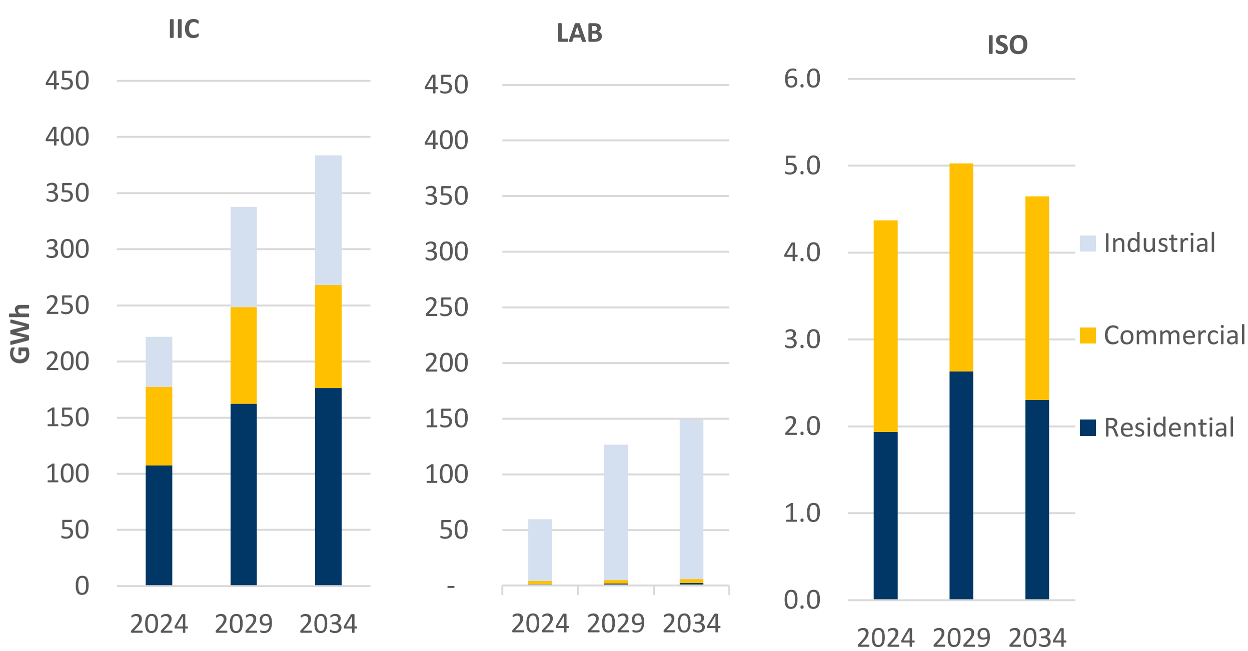


Figure 2-6. Cumulative Achievable Potential by System, Sector, and Time Period: Mid Program Scenario Under Mid Rates



Note: The Y axis differs for the ISO system to make the presentation clearer

From the results presented above, the following observations can be made:

- **Province-wide, the residential sector offers the highest savings potential in the initial five years, while the industrial sector appears to offer the highest savings potential by the end of the study period:** In the initial years, residential savings comprise over 40% of the potential, which is greater than either of the other sectors. However, by the end of the study period, the industrial sector offers nearly half of all savings potential in the province (47%), which is approximately split evenly between the IIC and LAB systems. It should be noted that the majority of these savings stem from the six transmission-level customers for whom a top-down analysis of the savings was applied, rather than the bottom-up analysis applied in all other segments. A key difference is that in the residential and commercial sectors cumulative savings taper off later in the study period due to lighting and heat pump standards changes, program participation and market transformation.

- **The IIC system residential sector savings are substantial due to the high penetration of electrically heated homes:** More than half of the savings in the IIC stem from the residential sector, and these savings grow throughout the study period. This indicates that savings are not coming from lighting measures alone, as residential lighting opportunities are expected to be largely eliminated by the EISA standards changes and market transformation effects by 2025.

- **Commercial sector savings in the ISO system make up over half of the remaining savings potential in that system:** While the commercial savings are curtailed in the initial years due to lighting market transformation, there remains significant commercial sector potential in the ISO system by the end of the study period.

The average annual savings by segment are presented below for the first five years (**Figure 2-7)** and the last ten years (**Figure 2-8**) of the study period. Residential segments are coloured dark blue, commercial segments are yellow, and industrial segments are light blue. The grey line provides a rolling total as a percent of overall savings.

Figure 2-7. Province-Wide Achievable by Segment (GWh): Mid Scenario Under Mid Rates, Average Annual (2020-2024)

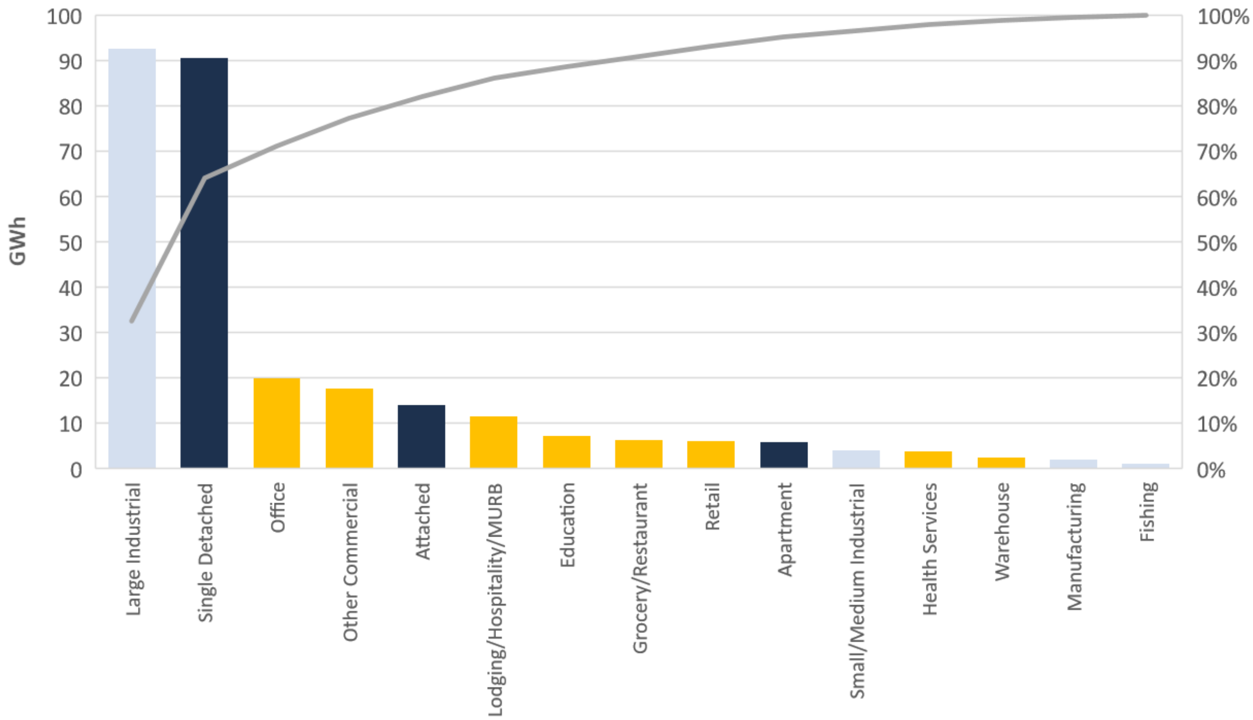
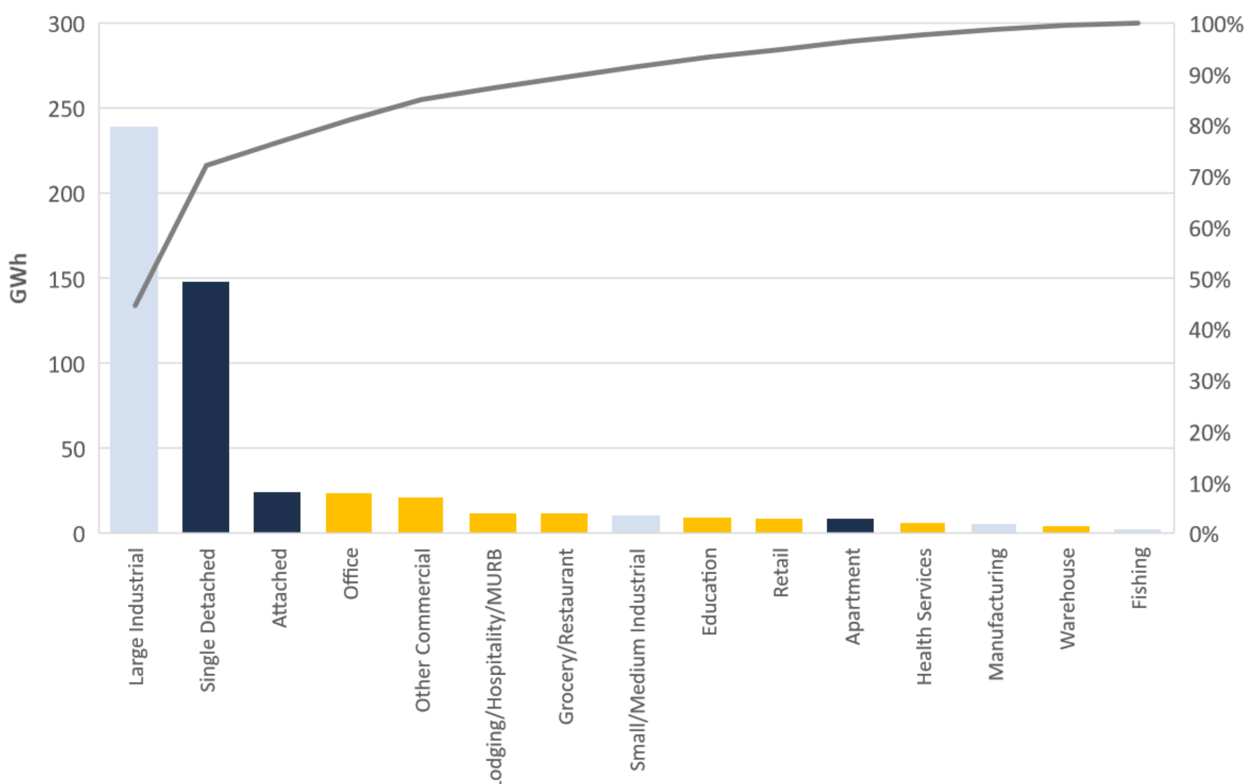


Figure 2-8. Province-Wide Achievable by Segment (GWh): Mid Scenario Under Mid Rates, Average Annual (2025-2034)



Inspection of the segment level cumulative savings reveals the following:

- **Large industrial has the most potential throughout the study period, and its portion of the overall potential grows even larger by the end of the study period:** The high energy usage per facility in the segment makes for significant potential savings. Once again, it should be noted that the top-down analysis did not reveal which measures drive these savings, thus there could be value in further studying this segment to verify these savings levels on a facility-by-facility basis, and to determine the key savings technologies.

- **A substantial portion of annual savings in the initial years are found in the single-family home segment**: Although the savings in this segment remain high throughout the study period, they are lower in the later years of the study as lighting savings drop out. Savings in other residential segments are much lower due to the lower number of customers in the apartments and attached homes segments, in addition to the higher barriers to many efficiency measures faced by these customers.

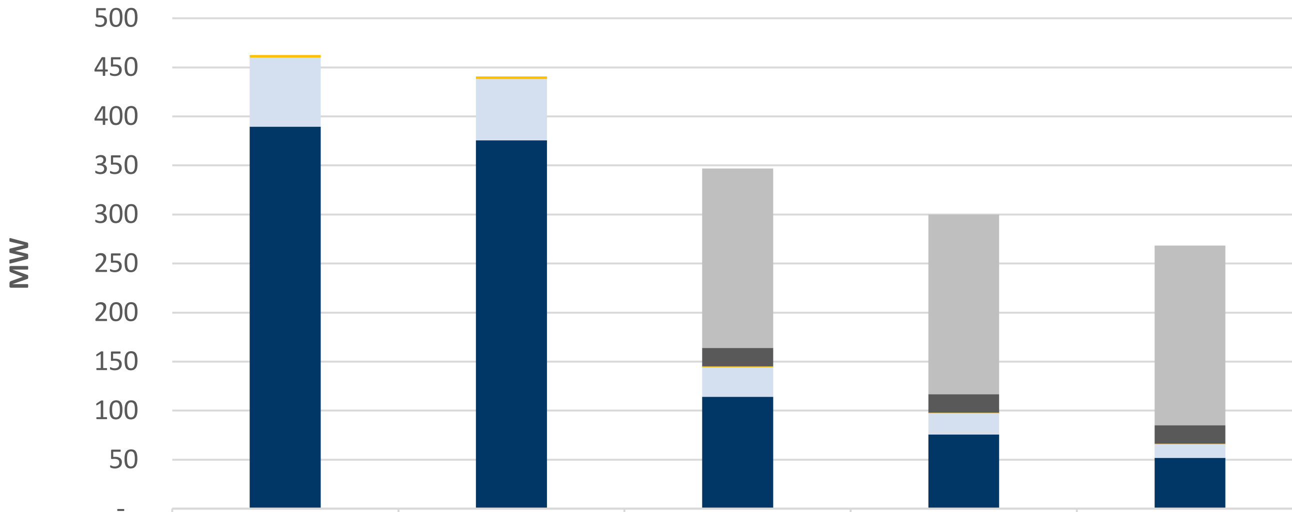
- **The top five segments represent more than 80% of the potential annual savings**, which may justify focusing CDM program efforts on these segments.

PEAK DEMAND REDUCTION POTENTIALS

The combined peak demand potential from energy efficiency (EE) and demand response (DR) programs are presented below in **Figure 2-9**. The efficiency program savings were assessed using the DEEP model first, and then the utility load curve was adjusted to account for these peak demand savings. These new utility load curves were then applied in the DR Model to arrive at the DR potential.

For the DR potential, only the highest yielding scenario for each of the systems (IIC and LAB) is presented in the results as these scenarios best capture the existing curtailment potential (please see Chapter 4 for further details on the DR Scenario results). The DR savings for the ISO system were not assessed due to the complexities of applying demand response programs to small local generation systems.

Figure 2-9. Peak Demand Potential Savings for DR and EE Programs by System Under Mid Rates[22] (2034)



	Technical	Economic	Upper	Mid	Lower
IIC (DR)			183	183	183
LAB (DR)			19	19	19
ISO (EE)	3	3	1	1	1
LAB (EE)	70	63	30	22	14
IIC (EE)	390	375	114	76	52

From these results, the following observations on demand reduction potential can be made:

- **The demand response programs offer higher demand reduction impacts than the efficiency measures under all EE program scenarios:** Demand response potential in the province is high when benchmarked

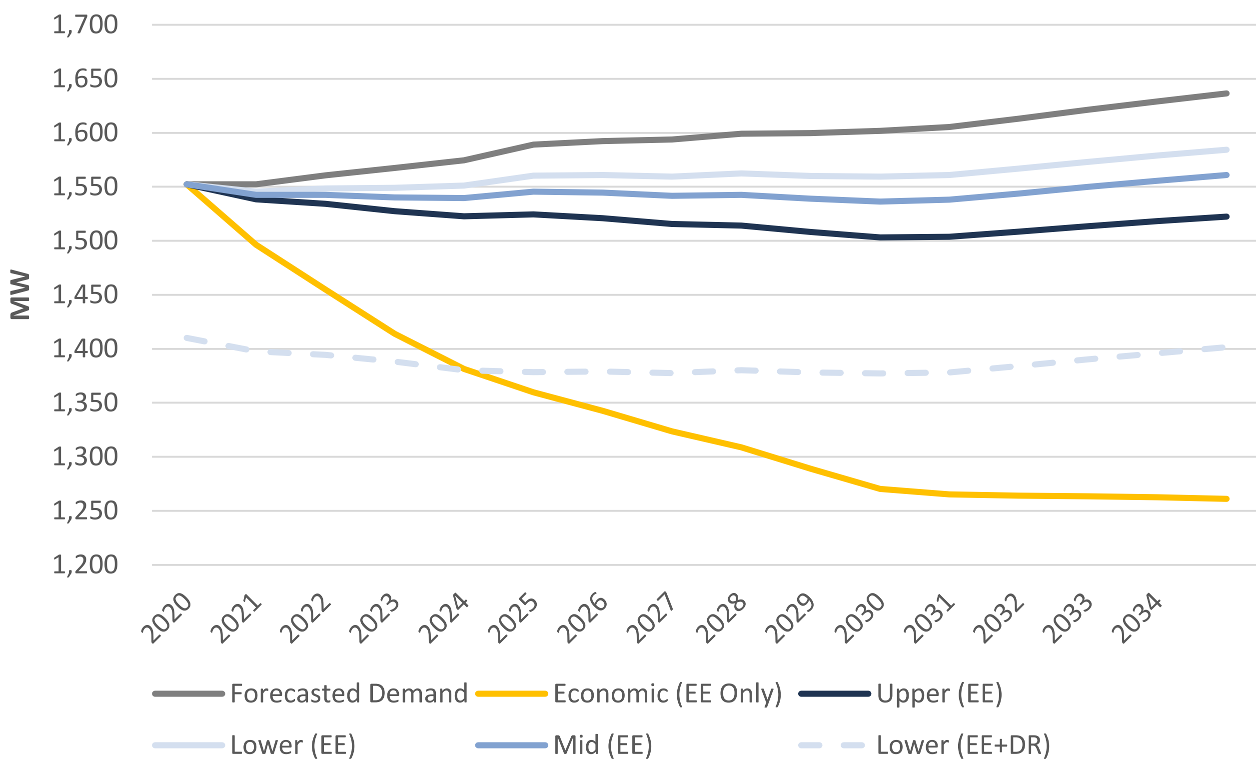
[22] DR potentials include existing and potential peak demand impacts as assessed in the DR model and described in Chapter 4 of this report. Because the model does not consider interactions among DR measures at the technical and economic potentials level, the results are not considered additive, and are therefore not included in the graph.

against other jurisdictions (see Chapter 4 for more details), and it delivers more demand reduction than any of the all efficiency program scenarios.

- **The Mid and Upper EE program scenarios offer significant increases to peak demand reduction potential, particularly in the IIC system:** While all EE program scenarios offer notable peak demand reductions, the Upper and Mid EE program scenarios offer significantly higher peak demand potentials than the Lower scenario, as was the case for consumption savings. Nonetheless, the EE peak demand potential remains much lower than the economic potential. If the NL Utilities continue to seek demand savings in the IIC system, there may be opportunities to tune higher program incentives on EE measures that offer the highest peak demand savings.

Figure 2-10 and **Figure 2-11** below show the peak demand impacts from EE and DR in the IIC and LAB systems respectively.

Figure 2-10. Peak Demand Potential Savings for DR and EE Programs Under Mid Rates (IIC)

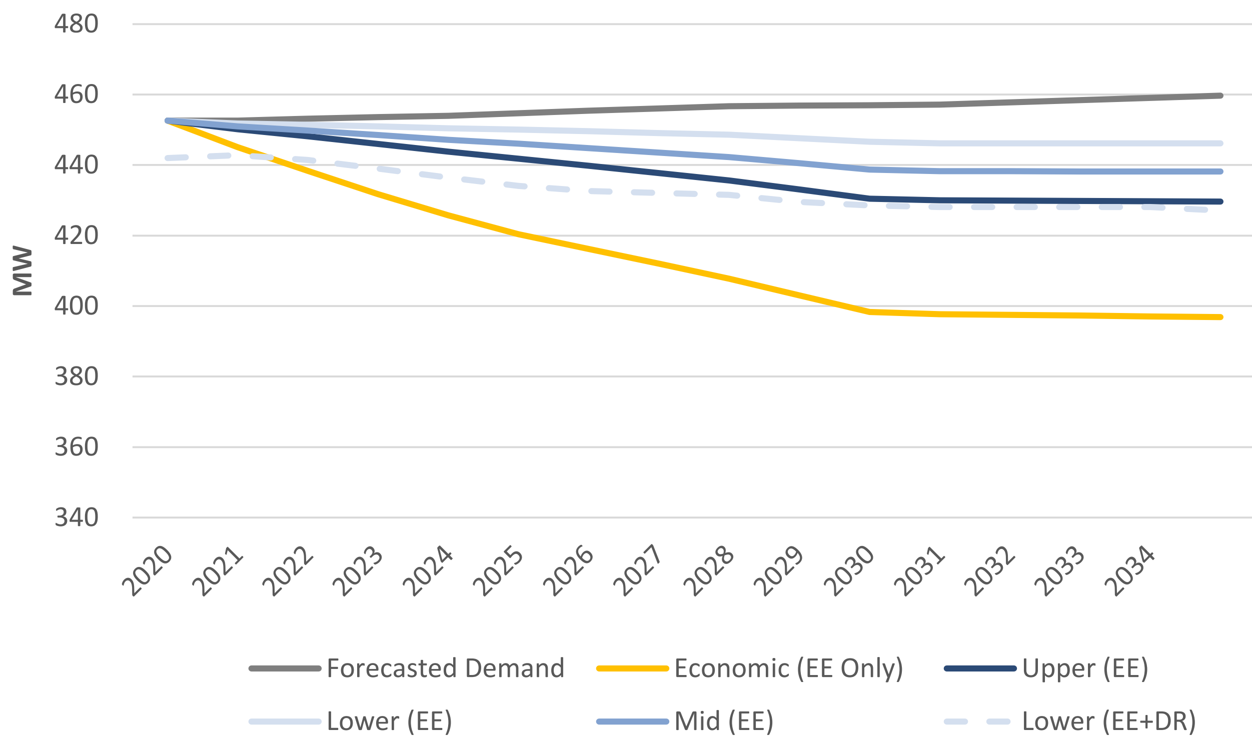


From the above figure it can be seen that the DR peak demand reduction far outweighs the EE peak demand potential in all years.

- **Much of the DR potential is already captured in the current industrial and commercial curtailment programs:** The dashed grey line reveals a slight dip in the initial years as expansion of the DR programs offsets overall system peak demand growth. Chapter 4 provides further details on the DR potential.

- **The combination of expanded DR programs and EE programs can effectively offset peak demand growth in the IIC system:** The dashed grey line remains at or below 1,400 MW for most of the study period, except the final years. This represents the combined impact of the DR programs and the Lower EE program potential, suggesting that a modest increase in EE programs potential by strategically targeting peak demand reducing efficiency measures could help ensure stable peak demand in the IIC system throughout the study period. The initial dip in peak demand in the initial years in the dashed Lower EE programs + DR line is caused by an overall projected dip in forecast peak demand combined with a ramp up in new DR program potential, over and above current curtailment (see Chapter 4 for details on the additional DR potential).

Figure 2-11. Peak Demand Potential Savings for DR and EE Programs Under Mid Rates (LAB)

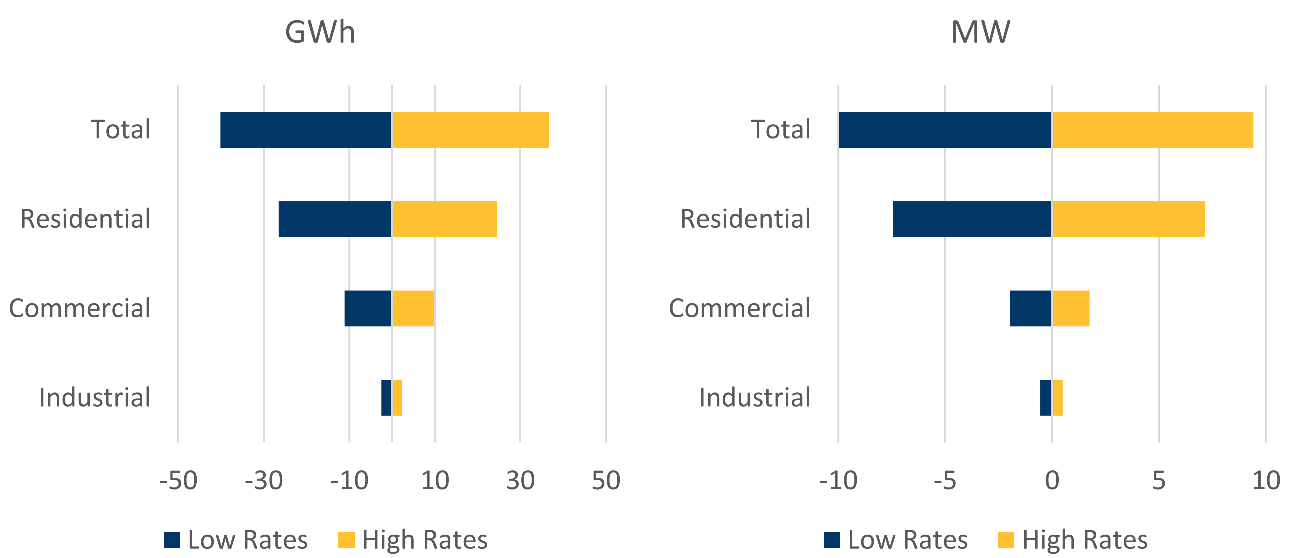


From this chart it can be seen that the LAB system has less DR potential than in the IIC system, and that current peak demand can be maintained or reduced through either EE or DR programs. Further details on the LAB DR program potential can be found in Chapter 4.

IIC SYSTEM SAVINGS SENSITIVITY ANALYSIS

The NL Utilities provided three customer rate scenarios for the IIC system to reflect uncertainty over future rates for commercial and residential customers after the Muskrat Falls generation facility becomes fully commissioned. In the following charts, the impact of the rate sensitivity cases is presented for achievable efficiency program savings.[23] Detailed results tables for the cumulative savings potential for the Upper and Lower program scenarios under the High, Mid and Low rates cases are provided in Appendix F. Overall the achievable potential for the Low-rates case was on average 18% lower than the Mid rates, while the achievable potential for the High-rates case was 20% higher than the Mid-rates case. It should be noted that the sensitivity analysis was not applied to the Large Industrials segment, as customer rates were not an input to the top-down analysis performed for that sector.

Figure 2-12. Impact of Customer Rate Scenarios on Cumulative Achievable Savings by segment: Mid Program Scenario (IIC - 2034)



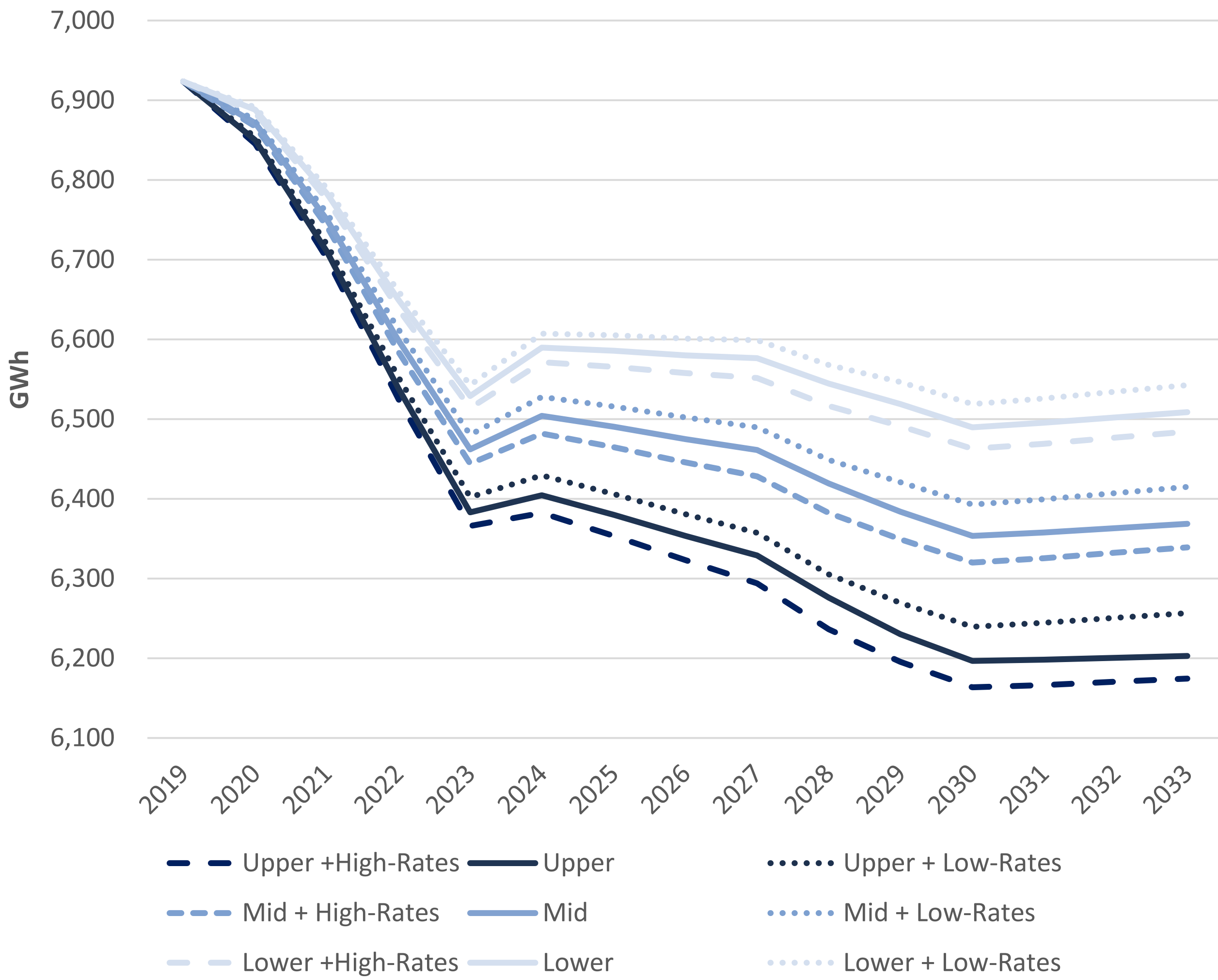
From the tornado graphs above, it can be seen that the High-rates case results in a greater adoption of efficiency measures, while Low-rates reduces the uptake of efficiency measures. Proportionally the increase from raising rates appears to be similar to the decreases when rates are lowered. Overall the majority of the impact is seen in the residential sector.

Below, the impact of the various rate scenarios on the progression of cumulative savings in the IIC system is presented (**Figure 2-13**). The following figure illustrates how the various rate scenarios would impact cumulative

[23] The DR program savings are not sensitive to absolute customer rates (Time of Use rates are assessed based on-to off-peak ratios) so the sensitivity analysis is limited to the EE program potentials. Further details on the DR potential findings are provided in Chapter 4 of this study.

savings under the Lower and Upper program scenarios. The annual savings for each customer rate scenario broken down by sector is provided in the appendix.

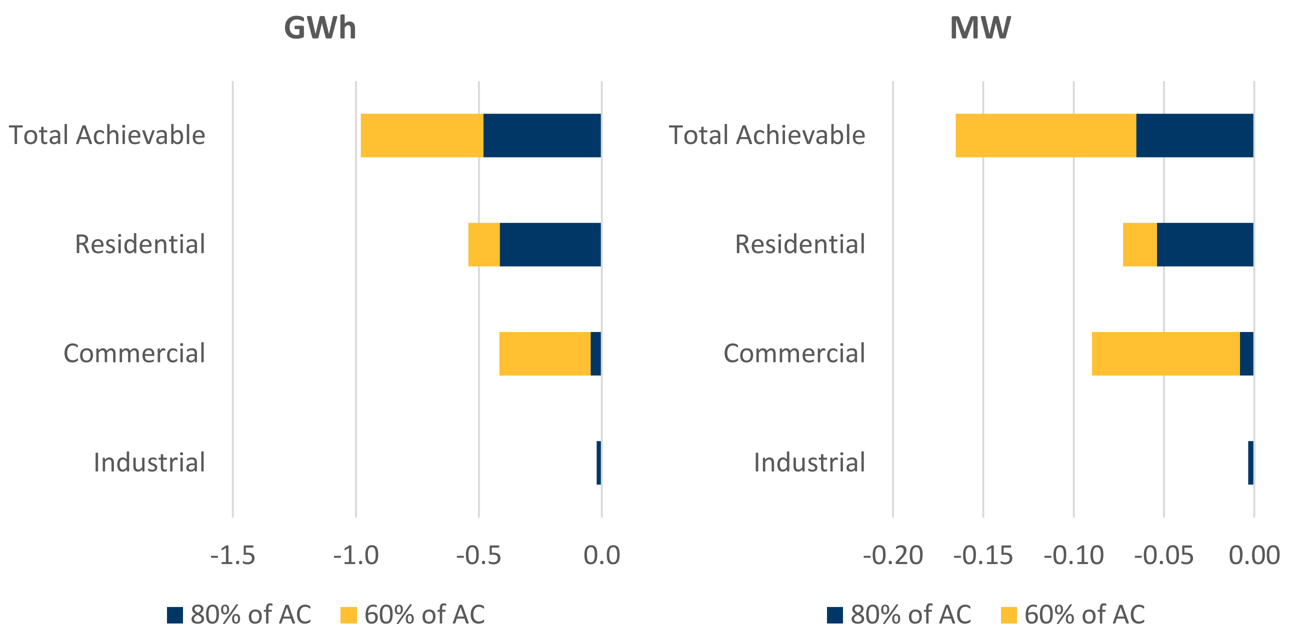
Figure 2-13. Impact of Customer Rates on the Cumulative Achievable Potential (IIC)



From the above figure it is clear that achievable savings are only marginally sensitive to the customer rate cases applied. Overall it is found that the achievable potential will increase or lower by 10% under each rate case as compared to the mid-rates case, which is attributed to two key reasons. First, the rate scenarios were not applied in the Large Industrial Segment analysis, which account for close to half of the overall cumulative savings by the end of the study period. Second, while customer rates are an important factor in determining the economics for adopting efficiency measures, market barriers also play a key role, tempering the sensitivity of the program savings to the various rate scenarios.

Finally, the impact of reduced avoided costs of capacity on the cumulative potential in the IIC system was assessed and the results are presented in **Figure 2-14** below. As discussed previously, the avoided costs of capacity for the IIC system range between $420 to $440 per MW over the study period, which helps most measures to be cost-effective under the TRC screen applied in the DEEP model. The following figure illustrates how reduced avoided capacity costs would impact cumulative savings (**Figure 2-14**).

Figure 2-14. Impact of Avoided Costs of Capacity Scenarios on Cumulative Achievable Savings: Mid Program Scenario (IIC – 2034)



From the above figure, the following observations are made:

- **The cumulative achievable potentials are much more sensitive to changes in customer rates than they are to changes in the avoided costs of capacity: Figure 2-14** and **Figure 2-12** reveal that changes to the avoided costs have much less impact on the achievable potential than changes to customer rates. This is a logical finding, as the achievable potential is driven by customer economics, which is directly affected by changes to customer rates (higher electricity rates increase benefits to customers from EE measures). On the other hand, customers are not directly exposed to avoided costs, and so avoided costs changes impact only customer adoption when they alter the range of measures included in the economic potential; measures that are not included in the economic potential are not considered for customer adoption under the achievable potential.
- **The range of tested avoided costs does not significantly impact the achievable potential:** Reducing the avoided costs of capacity impacts the achievable potential when they cause a measure to fail the TRC screen. Even at 60% of the currently projected avoided costs, the IIC system avoided costs of capacity remain relatively high compared to other jurisdictions. As a result, the reductions in avoided costs of capacity are insufficient enough to cause many measures to fail the TRC screen (which was set at 0.8). Thus, the vast majority of measures remain within the economic potential, making them available under the achievable potential scenarios.

3. EFFICIENCY PROGRAM SAVINGS POTENTIAL

The following graphs and tables present Newfoundland and Labrador's CDM program efficiency savings potential. Program savings refer to the savings from measures that are incentivized through programs in a given year. They are most representative of annual program savings and can be used as an input to CDM program planning to help establish savings objectives, and to determine which sectors, end-uses, and measures hold the most potential.

Three achievable potential scenarios were assessed in this potential study: Lower, Mid, and Upper. By varying factors such as incentive levels[24] and barrier reduction strategies between scenarios, the study offers insights into their respective impacts on program savings. A summary of the assumptions associated with each scenario are presented below (**Figure 3-1**). Detailed tables of the input assumptions applied for each program can be found in Appendix E.

Figure 3-1. Program Scenario Assumptions

Lower	• **Lower Achievable Potential** Applies current Utility CDM program incentive levels and enabling activities, but includes the full range of cost-effective technologies, and disregards any budget constraints.
Mid	• **Mid-Range Achievable Potential** Applies increased incentive levels to reflect increased investments in CDM programs compared to the current portfolio.
Upper	• **Upper Achievable Potential** Applies increased incentive levels, and includes further investments in enabling activities to address customer barriers to adoption.

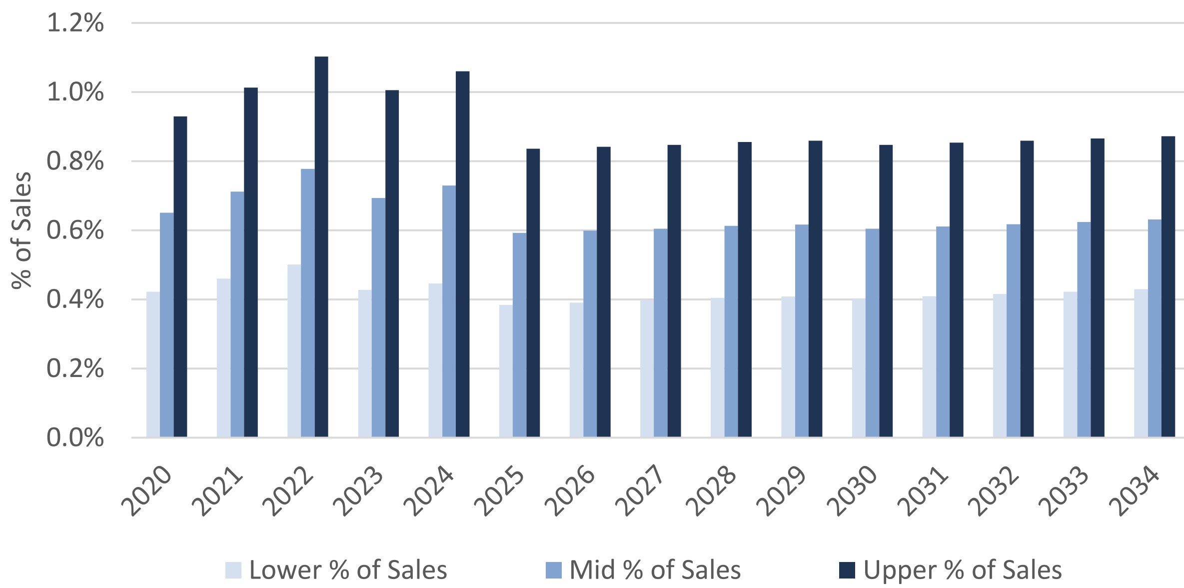
The results that follow highlight the achievable potential savings under each scenario, for each of the current takeCHARGE programs, as well as for potential new programs. Results are presented for each program under each scenario, as well as breakdowns of program savings by end-use and the top ten measures in each sector. All results were generated under the Mid-rates case, representing a middle point escalation of customer rates between the mitigated and unmitigated rate projections.

[24] Incentive levels refer to the portion of a measure's incremental cost is covered by a program incentive.

ANNUAL PROGRAM SAVINGS

Forecasted annual program savings for all programs are expressed as the portion of annual sales in each year of the study period for each of the program scenarios below (**Figure 3-2**). We present IIC + LAB savings together as the takeCHARGE programs are delivered consistently throughout these two systems. Due to the extremely high avoided costs of generation and subsidized rates for customers in ISO system, NL Hydro offers tailored programs for the ISO system with elevated incentive levels and enabling strategies (such as direct install program implementation) to address the specific challenges of these remote communities. The annual savings are provided as a portion of overall ISO system sales in a separate chart (**Figure 3-3**).

Figure 3-2. Program Savings as a Portion of Annual Sales: Lower, Mid and Upper Program Scenarios Under Mid Rates (IIC+LAB)



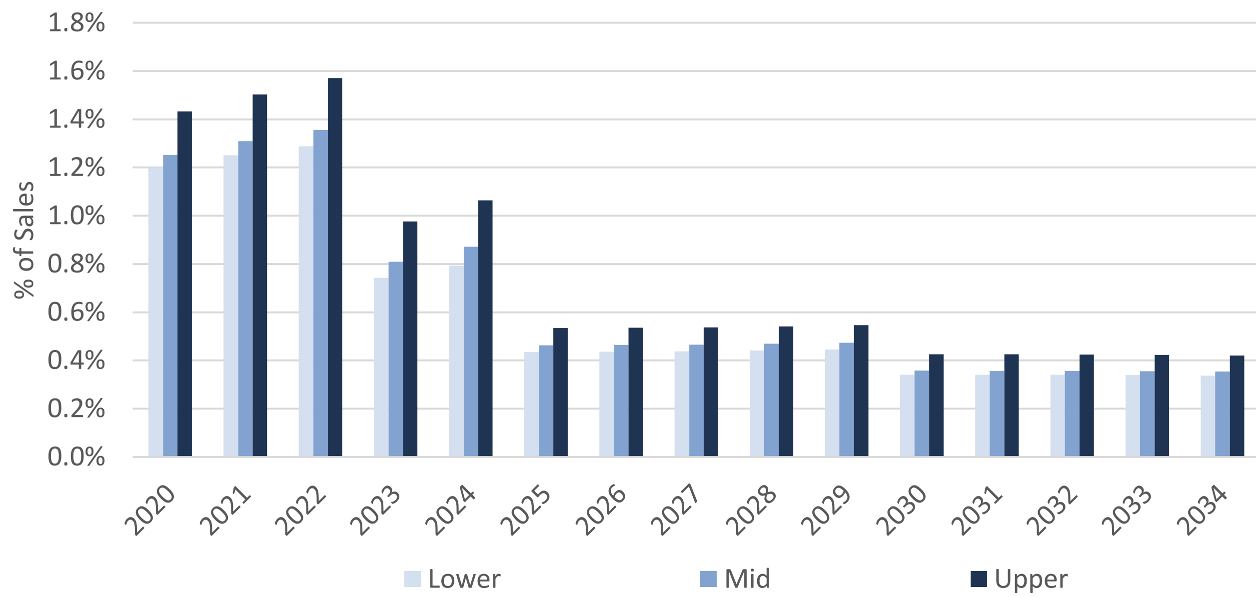
From these results, the following observations can be made:

- **Savings range from 0.4% to 1.1% of sales in the initial five years of the study period:** Savings under all program scenarios are highest in the initial five years. The Lower program scenario achieve 0.4%-0.5% savings per year in this period, while the Upper scenario savings exceed 1.1% of sales, reaching a peak in 2022 and 2024. Starting in 2025 the annual program savings drop significantly as almost all residential lighting and a significant portion of commercial lighting savings are eliminated by the 2023 and 2025 standards updates. Also, heat pump standards improve in 2023 and 2025, further cutting savings from those measures. However, it should be noted that there is an increase in savings between 2023 and 2024 as rates rise and new measures and programs added in 2020 complete their ramp up period.

- **After a steep drop between 2024 and 2025, program savings remain stable for the remainder of the study period.** Once residential and standard commercial lighting has been removed from the programs, annual savings drop to a lower level. As commercial lighting equipment are gradually replaced with long life expectancy LEDs, the number of replacement opportunities declines and with it, savings that can be achieved through programs. However, as customer rates gradually increase, a steady flow of HVAC and envelope improvement opportunities persists over the remainder of the study period.

The ISO system exhibits a similar pattern, with a steep drop in program savings between 2024 and 2025, although the reduction is much more pronounced (**Figure 3-3**).

Figure 3-3. Program Savings as a Portion of Annual Sales: Lower, Mid and Upper Program Scenarios Under Mid Rates (ISO)



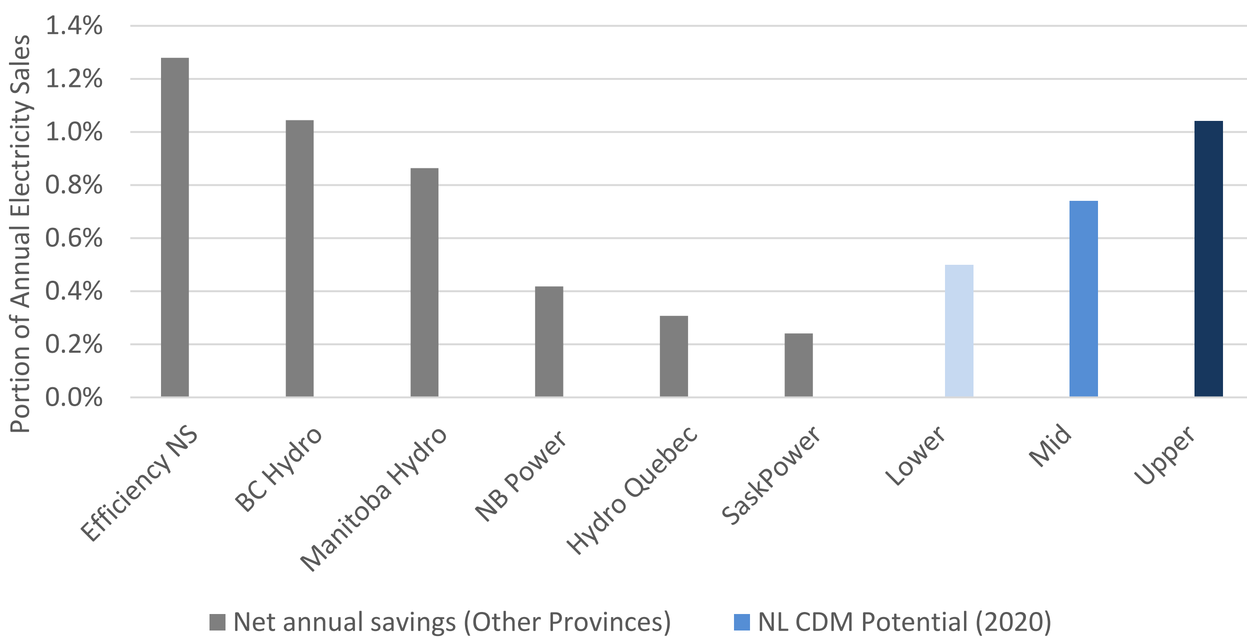
The follow observations are made from the figure above:

- **ISO savings in the initial years are higher than for the later years, and the program scenarios show much less spread in their results:** Savings in the initial years range from 1.2% to 1.6%, peaking in 2020 before the first EISA standards updates take effect. The high savings are driven by the high incentive levels and enabling strategies employed in the Isolated Residential Program (100% incentives and direct install implementation). With the high incentives in the residential program, there is little impact under the Mid program scenario, and the Upper program scenario applies just a barrier reduction impact in the residential program, thus the program scenario results are closely grouped, suggesting it would be a challenge for NL Hydro to generate significantly higher savings than the current ISO system programs deliver.
- **ISO savings are highly driven by lighting measures in the initial years, and envelope and HVAC measures in the later years:** The high incentives offered for ISO customers and enabling strategies cause these programs to be very sensitive to lighting savings, which leads to notable drops in annual savings in 2023 and 2025 as each phase of the EISA standards is applied. Moreover, due to the low penetration of electric heating among ISO system customers, there are fewer HVAC and envelope measure savings available to the programs from 2025 to 2034, and thus the annual savings drop. However, it should be

noted that there is an increase in savings between 2024 and 2023 as rates rise and new measures and programs added in 2020 complete their ramp up period.

For comparison, the CDM program scenario savings in 2020 are compared to a selection of other Canadian Province electric efficiency program savings (**Figure 3-4**), where results were available. Further details and references for the data from other provinces can be found in Appendix E (see **Table E-31**).

Figure 3-4. Annual CDM Program Potential (2020) and recent Electric Efficiency Performance in Other Canadian Provinces

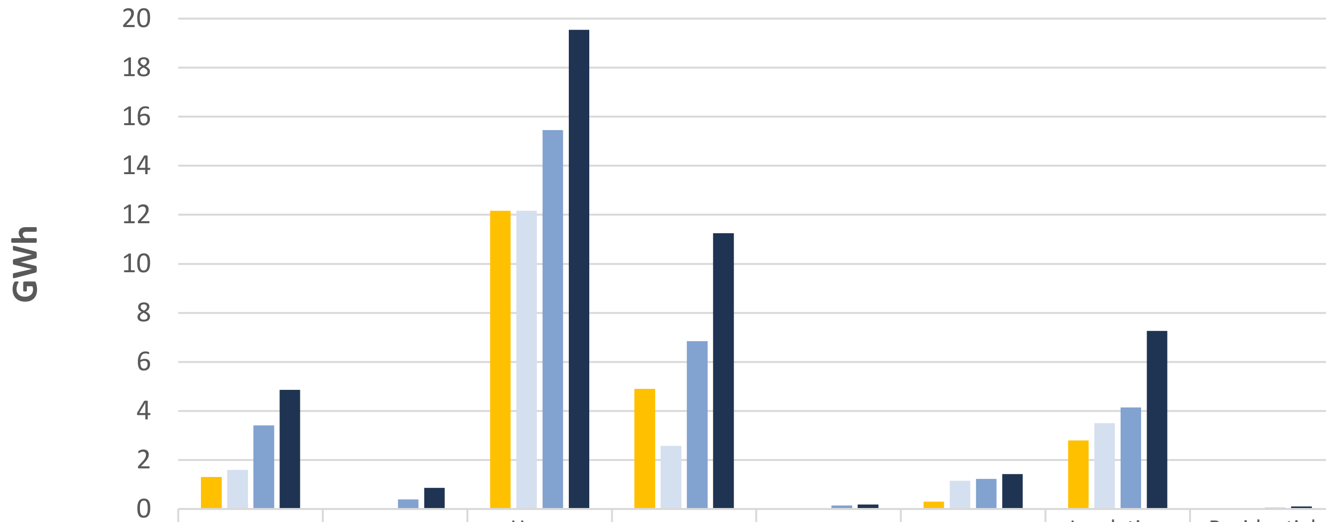


Overall the results indicate that the NL CDM Potential in 2020 places NL within the middle range of savings when compared to other provinces. The Lower program scenario delivers savings that are comparable, but exceed, the lesser performing provinces (New Brunswick, Quebec and Saskatchewan), which all exhibit low electricity rates for customers. The Upper program scenario would place NL within Canada's leading provinces for efficiency programs. While this figure offers a useful comparison, it is important to note that energy prices and fuel mixes vary by province, which have a significant influence on the annual savings achieved.

RESIDENTIAL PROGRAMS

Below, current residential program savings[25] are presented alongside modeled potential savings for each program scenario for 2020 under the Mid-rates case (**Figure 3-5**) for the takeCHARGE programs covering the IIC and LAB systems collectively. Current values are compared for the first year of the study (2020) as CDM program numbers are not available for later years. Program savings potentials for the initial five years (2020-2024) are also presented to show expected program savings evolutions (**Figure 3-6)**.

Figure 3-5. Comparison of Residential Program Savings: Current programs, Lower, Mid and Upper Program Scenarios Under Mid Rates (2020)



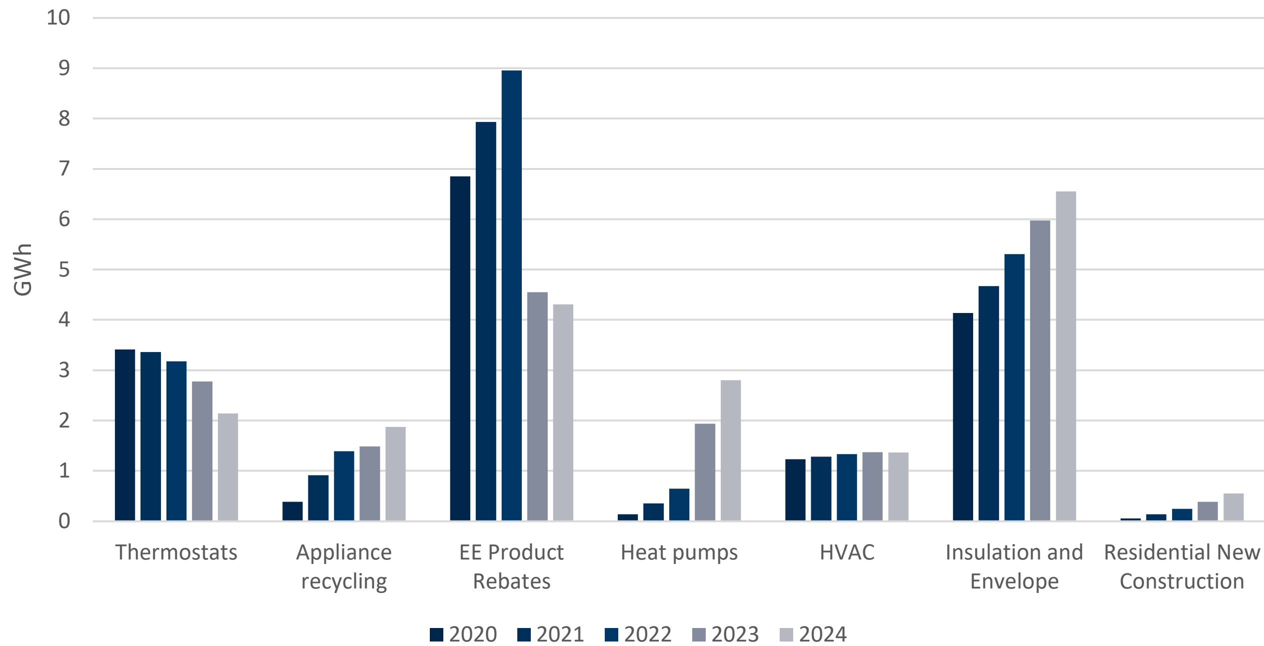
	Thermostats	Appliance recycling	Home Energy Report	EE Product Rebates	Heat pumps	HVAC	Insulation and Envelope	Residential New Construction
Current Prog.	1.30		12.16	4.90		0.30	2.80	
Lower	1.59	0.00	12.16	2.57	0.00	1.15	3.51	0.00
Mid	3.41	0.39	15.45	6.85	0.14	1.23	4.14	0.05
Upper	4.85	0.86	19.55	11.24	0.18	1.43	7.27	0.10

Note: Current Program savings are derived from either the 2019 CDM Program Plan for 2019, or evaluated program savings from 2017 and/or 2018 where available.

From the residential program comparisons, it can be seen that some programs exhibit a somewhat larger potential in 2020 than in the current plans or evaluation report: This is largely because the results shown apply the Mid-rates case, which are higher than current customer rates, thereby they increase the efficiency benefits to customers which drives increased adoption. The model was calibrated under the Low-rates case (fully mitigated) and the results are provided in Appendix F.

[25] Current Program savings are derived from recent CDM program evaluation reports or the 2016-2020 Energy Conservation Plan (2015, NL Hydro and NF Power) using 2019 planned savings where recent evaluations were not available.

Figure 3-6. Residential Program Savings Evolution (2020-2024): Mid Program Scenario Under Mid Rates



Note: Home Energy Reports are not presented in the above graph as the savings do not change by year.

A review and comparison of the above figures reveals a few key trends:

- **New programs and programs with measures not currently offered in the takeCHARGE portfolio show notable growth over the 2020-2024 period: Figure 3-6** presents annual program savings for each residential program over the 2020-2024 period. To account for the expected ramp-up in demand attributed to growing awareness and program effectiveness for newly offered programs and measures, the model applied a program uptake growth factor in the initial years (Appendix E Measure Lists provides details which measures in the model are not currently offered in the takeCHARGE programs.) The impact of new programs and measure incentives can be seen on the Appliance Recycling, Heat Pumps, HVAC, Insulation and Envelope, and Residential New Construction programs.

- **Thermostats Program:** The Thermostats program captures a significant amount of savings under the Lower program scenario, and shows substantial growth when incentives are increased and enabling strategies are employed under the Mid and Upper program scenarios. The program evolution **in Figure 3-6** indicates that thermostat program savings will drop with time as the market for programmable and electronic thermostats becomes saturated.

- **Appliance Recycling:** The NL Utilities do not currently offer an appliance recycling program, primarily due to the lack of consistent provincial appliance recycling and Freon removal facilities that prevent a province wide program being offered at this time. This program was added under the Mid and Upper program scenarios, and demonstrates marginal potential in 2020, but with a significant ramp up in the initial years.

- **Home Energy Reports:** This program applied the average savings per home from the 2018 program evaluation report, which is the same values as presented under the Current program savings. The model was set to reach 30%, 40%, and 50% of residential customers in the IIC and LAB systems. Overall, the ratios of the three program scenarios largely follows the program coverage on the basis of the portion of single family and attached homes that receive reports under each scenario. The model did not account for any changes in savings per home or program growth by year, and thus this program is not included in **Figure 3-6** as the savings remain constant in each year.

- **EE Product Rebates:** The EE Rebates Program includes residential lighting and efficient appliance measures (See Appendix E for a full measure list). This program exhibits lower savings in 2020 than were achieved in past years (current value is taken from the last available data in the 2016-2020 Plan). Lighting savings appear to be dropping as compared to past years as the market transforms and saturates and efficient product performance evolves, which may impact the expected uptake and savings as compared to the last NL Utility projections. A possible explanation of the drop in residential lighting savings is provided below in a call-out box.

Residential Lighting Savings

This study shows a notable drop in lighting savings compared to recent CDM program performance. While there are still many sockets in NL that contain halogen or incandescent bulbs, the market is transforming as LEDs become more and more common, which may reduce the opportunities for CDM programs to influence LED bulb purchases. A number of factors lead to uncertainty over LED savings in the coming years.

First, as the market transforms, free ridership could rise in lighting programs. The model applied a 0.76 NTGR for residential lighting, which was taken from the 2017-18 program evaluation. Given the fast pace of lighting transformation this NTGR may drop in the next evaluation. Moreover, due to the changing existing bulb mix in homes, this study used a lower average savings per bulb than past program evaluations (See Appendix E for further details). This is further supported by preliminary result from a recent socket study performed in 2019 which indicates that the saturation of LEDs in NL homes has jumped from 42% in 2018 to 51% in 2019

While the lighting savings in this report may be lower than in past program years, the results still show significant potential, which suggest that residential lighting may still offer a valid, albeit somewhat reduced, contributor to residential CDM program savings in the coming years before possible standards changes are enforced.

- **Heat Pumps:** Currently, NL Utilities offer financing for customers who wish to install heat pumps, but no incentives. This approach was taken due to the high levels of natural adoption already occurring in the market. It should be pointed out that the Heat Pumps program characterized in the analysis would incentivise customers to install a better than standard efficiency model, and only counts the incremental costs and savings as compared to a standard heat pump. Under the Mid and Upper scenarios, the model applied a 50% incentive and increasing barrier reductions. Chapter 5 includes a separate analysis of heat pump adoption in general for customers switching from electric baseboard heating, oil heating or wood stoves. While the savings from this program are insignificant in 2020, **Figure 3-6** reveals that if incentives were offered to efficient heat pumps the program savings could increase steeply between 2020 and 2024 as the program ramps up and customer rates potentially rise.

- **Heating Ventilation and Air-Conditioning (HVAC):** The HVAC program shows a significant bump in savings as a result of the increased customer rates under the mid-rates case. Customer rates have a significant impact on measures with long EULs, such as HVAC equipment. Moreover, the modelled program includes a wide variety of equipment options covering all commercially available opportunities which may have further led to higher savings than the current HVAC CDM program (See the detailed measure list in Appendix E for a full list of HVAC measures in the model).

- **Insulation and Envelope:** As with the HVAC program, the Insulation and Envelope program offers a notable increase in savings potential as compared to the current CDM program, as a result of the increasing customer rates, additional measures being incorporated, and the long EULs for measures in this program. There is little difference between the Lower and Mid program scenarios as the incentive levels were changed only from 60% to 65% respectively under the scenarios. This program does exhibit a significant jump in the Upper scenario, suggesting that investing in enabling strategies could be an effective way to expand the market for envelop upgrades. Moreover, as electricity prices rise and a handful of new measures become cost-effective and are included in the program (such as professional air-sealing and efficient windows), the savings ramp up significantly over the initial five years of the study period.

- **Residential New Construction (NC):** The NL Utilities do not currently offer a Residential NC program, so this program was added only under the Mid and Upper program scenarios. Results indicate that the savings from ENERGY STAR certified homes would be insignificant in 2020, but may grow steadily up to 2024.

END-USE BREAKDOWN AND TOP SAVINGS MEASURES

This section presents a breakdown of residential savings opportunities by end-use and lists the top-saving measures under the Mid program scenario, applying the Mid-rates case. Both the end-use breakdown and the summary of top measures are quantified using averages of annual program savings for the initial five-year period (2020-2024), as well as the average over the later ten-year period (2025-2034). Lifetime savings are presented by end-use and for each of the top measures to provide further context concerning the persistence of savings.

The top electrical savings measures in the residential sector are presented below (**Table 3-1**).They are ranked by the average annual savings, and observation of the table shows an important difference in the ranking on an annual savings basis as compared to the lifetime savings basis. The top residential savings measures ranked by total lifetime savings over the full study period is also provided (**Table 3-2**).

A measure's annual program savings will be counted each year towards the CDM program performance, but its impact on cumulative savings will vary greatly depending on each measure's EUL.[26] Presenting the measure

[26] For example, a measure with a 10-year EUL will be incentivized once and generate savings for 10 years, whereas a measure with a 1-year EUL (e.g. Home Energy Report) needs to be incentivized each year to maintain its impact on the cumulative savings at the grid level.

lifetime savings helps to illustrate which savings offer the most long-term benefits, even after an incentive program may be retired.

Table 3-1. Residential Top 10 Efficiency Measures: Mid Program Scenario Under Mid Rates

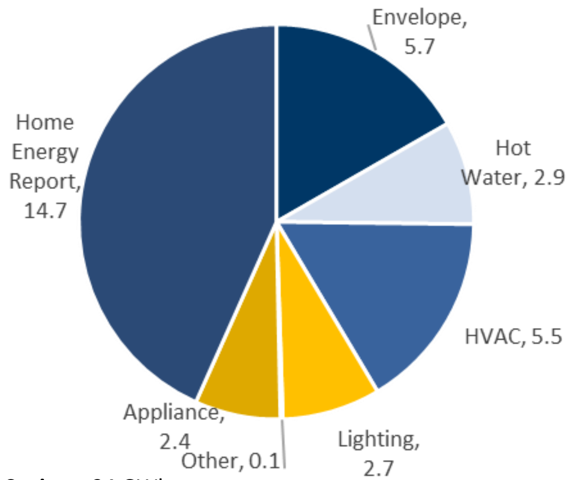
2020-2024		2025-2034	
Measure	**Average Annual Savings (GWh)**	**Measure**	**Average Annual Savings (GWh)**
Home Energy Report	15	**Home Energy Report**	15
Insulation	3.6	**Insulation**	1.9
Thermostats	3.0	**Mini-split Ductless Heat Pump (DMSHP)**	1.4
LED (Interior)	2.1	**Thermostats**	1.3
Low Flow Shower Head	1.4	**Efficient Windows**	1.1
Faucet Aerators	1.4	**Air Sealing**	1.1
Mini-split Ductless Heat Pump (DMSHP)	1.2	**ENERGY STAR Clothes Dryer**	0.66
Heat Recovery Ventilator	1.1	**ENERGY STAR Refrigerators**	0.62
Air Sealing	1.1	**Low Flow Shower Head**	0.59
Freezer Recycling	0.92	**Faucet Aerators**	0.58

Table 3-2. Residential Top 10 Efficiency Measures by Total Lifetime Savings: Mid Program Scenario Under Mid Rates

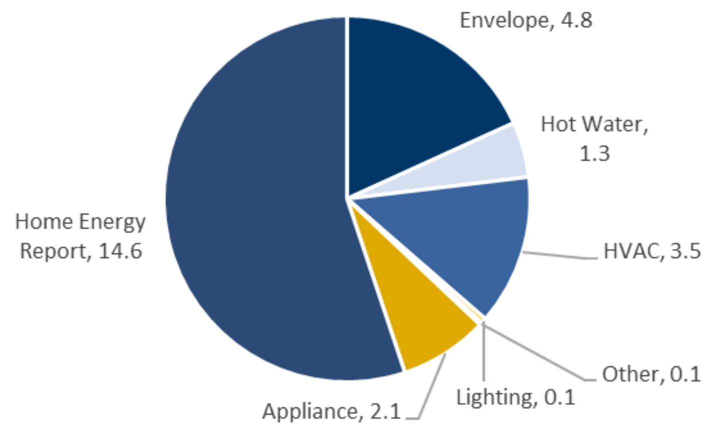
Measure	Total Lifetime Savings (GWh)
Insulation	978
Thermostats	356
Mini-split Ductless Heat Pump (DMSHP)	288
Efficient Windows	257
Air Sealing	246
Home Energy Report	220
Heat Recovery Ventilator	188
New Construction	155
Low Flow Shower Head	148
Faucet Aerators	145

A breakdown of residential average annual savings by end-use[27] is presented below (**Figure 3-7**) followed by lifetime savings (**Figure 3-8**), for comparison purposes.

Figure 3-7. Residential Annual Savings by End-Use (GWh): Mid Program Scenario, 2020-2024 (left) and 2025-2034 (right) Under Mid Rates

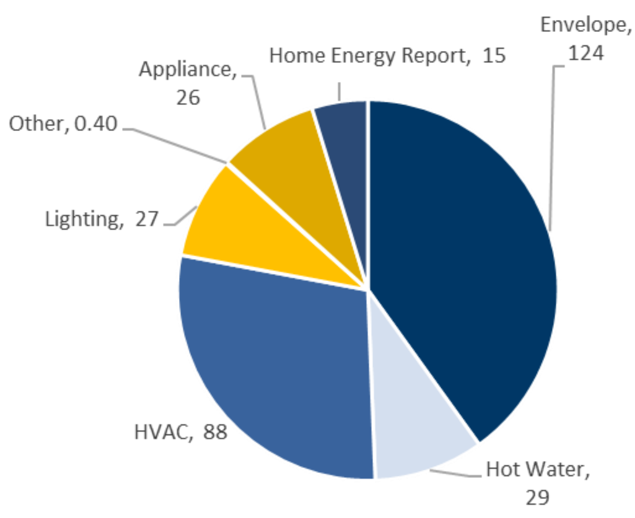


Total Savings: 34 GWh

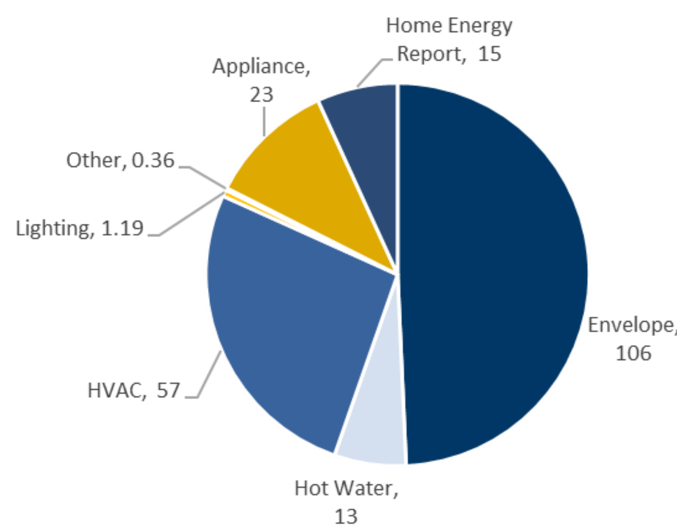


Total Savings: 27 GWh

Figure 3-8. Residential Lifetime Electricity Savings by End-Use (GWh): Mid Scenario, 2020-2024 (left) and 2025-2034 (right) Under Mid Rates



Total Savings: 309 GWh



Total Savings: 216 GWh

[27] A complete list of the measures included within each end use is provided in Appendix E.

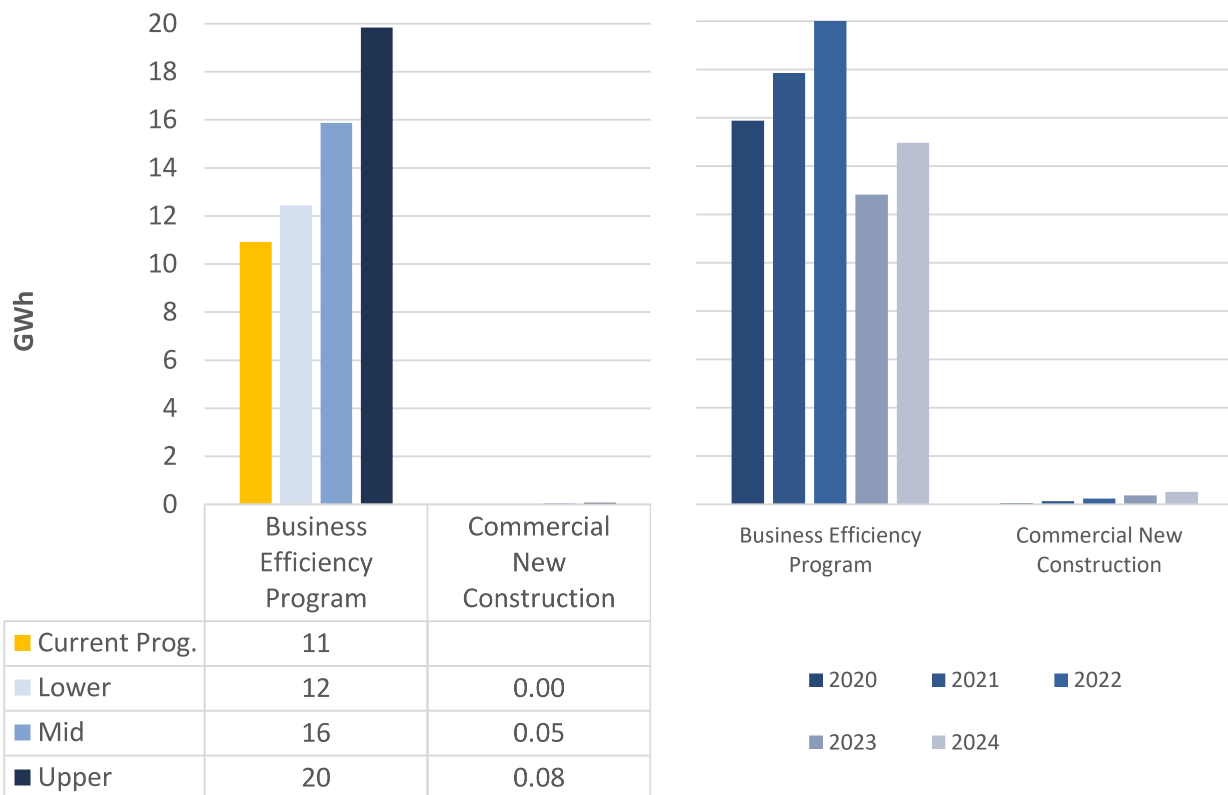
From these results, the following observations can be made:

- **Envelope measures provide significant annual savings and more than half of all lifetime savings by the end of the study period.** Contrary to the Home Energy Reports, envelope measures (with insulation, air sealing and efficient windows leading the group) contribute slightly more than 20% of annual program savings by the end of the study, but due to their long EULs they generate over 40% of lifetime savings in the initial 5 years (2020-2024), and close to 50% in the 2025-2034 period. This end-use shows constant growth in savings throughout the study period. These results demonstrate the value of investing in barrier and cost reducing efforts to promote envelope upgrades in new and existing homes in Newfoundland and Labrador.
- **Lighting measures only provide savings during the first five years.** Due to the assumption that future EISA lighting standards will come into effect in January 2023 (for Standard A-Lamps) and in January 2025 (for Specialty Reflector bulbs), no more savings from replacing A-lamps and reflector lamps with LEDs can be counted towards programs starting on these dates respectively. Overall program savings decline due to the loss of these measures. However, if the announced rollback on applying EISA standards to specialty lamps is enforced, or if the Canada does not adopt the same lighting standards as the US, there could be opportunities to promote efficient lighting in Newfoundland and Labrador homes beyond 2024.
- **As much as 50% of annual savings come from Home Energy Report (behavioural measure)**. This measure offers the single most important source of annual savings across the study period, and increasingly over time, reaching more than 50% of residential savings in the final years of the study. However, this end-use is among the lowest in terms of lifetime savings, due to its 1-year EUL. This means that if the program is discontinued, the savings would not persist in future years.
- **High Efficiency Mini-Split Heat Pumps show increasing savings if included in programs.** Heat pump adoption in NL has been growing considerably in the past few years, and the combination of possible electricity rate increases, and the high penetration of electric heating suggests that this will continue. Offering incentives for customers to adopt higher efficiency heat pump models jumps from the 8th most important saving measure in the first five years to the 5th in the later study years.

COMMERCIAL PROGRAMS ANALYSIS

Below, current commercial program savings[28] are presented alongside modeled savings under each program scenario for 2020 under the Mid-rates case (**Figure 3-9)** for the IIC and LAB systems collectively. Current values are compared for the first year of the study (2020) as CDM program numbers are not available for later years. The evolution of the annual savings for the initial five years under the Mid program scenario (2020-2024) are also presented. The Business Efficiency Program covers all non-residential customers (the commercial and industrial segments in this study) with the exclusion of the transmission-level (Large Industrial segment) customers.

Figure 3-9. Comparison of Commercial Program Savings (Left - 2020) and Program Savings Evolution (Right – Mid Scenario) Under Mid Rates



	Business Efficiency Program	Commercial New Construction
Current Prog.	11	
Lower	12	0.00
Mid	16	0.05
Upper	20	0.08

Note: Current Program savings are derived from either the 2019 CDM Program Plan for 2019, or evaluated program savings from 2017 and/or 2018 where available.

Observation of the above figure reveals the following:

- **Business Efficiency Program:** From the commercial program comparisons, it can be seen that the Business Efficiency Program exhibits a somewhat larger potential in 2020 than in the current plan. This

[28] Current Program savings are derived from recent CDM program evaluation reports or the 2016-2020 Energy Conservation Plan (2015, NL Hydro and NF Power) using 2019 planned savings where recent evaluations were not available.

is largely because the results shown apply the Mid-rates case, which are higher than current customer rates, thereby they increase the efficiency benefits to customers which drives increased adoption. The model was calibrated under the Low-rates case (fully mitigated) and the results are provided in Appendix F. The savings evolution reveals that lighting measures have a significant impact on this program's annual savings, as there is a notable drop in savings in 2023 when new standards for A-lamps are expected to take effect. It should be noted that unlike in the residential lighting, no socket study was available for commercial lighting, so the savings per bulb reflect past evaluation savings.

- **Commercial New Construction (NC):** The NL Utilities do not currently offer a Commercial NC program, so this program was added only under the Mid and Upper program scenarios. Results indicate that the savings will be insignificant in 2020, and despite steady growth up to 2024, the barriers to obtaining LEED and Net-Zero-Energy Ready building certification along with the limited rate of new construction in the province limit the savings for this program.

COMMERCIAL SECTOR END-USE BREAKDOWN AND TOP SAVINGS MEASURES

This section presents a breakdown of commercial savings opportunities by end-use and lists the top-saving measures under the Mid program scenario, applying the Mid-rates case. Both the end-use breakdown and the summary of top measures are quantified using averages of annual program savings for the initial five-year period (2020-2024), as well as the average over the later ten-year period (2025-2034). Lifetime savings are presented by end-use and for each of the top measures to provide further context concerning the persistence of savings.

The top electrical savings measures in the commercial sector are presented below (**Table 3-3**). They are ranked by the average annual savings, and observation of the table shows an important difference in the ranking on an annual savings basis as compared to the lifetime savings basis. A measure's annual program savings will be counted each year towards the CDM program performance, but its impact on cumulative savings will vary greatly depending on each measure's EUL.[29] Presenting the measure lifetime savings helps to illustrate which savings offer the most long-term benefits, even after an incentive program may be retired. The top commercial savings measures ranked by total lifetime savings over the full study period is also provided (**Table 3-4)**.

[29] For example, a measure with a 10-year EUL will be incentivized once and generate savings for 10 years, whereas a measure with a 5-year EUL (e.g. Recommissioning and Strategic Energy Management (RCx-SEM)) needs to be incentivized more frequently to maintain its impact on the cumulative savings at the grid level.

Table 3-3. Commercial Top 10 Efficiency Measures: Mid Program Scenario Under Mid Rates

2020-2024		2025-2034	
Measure	Average Annual Savings (GWh)	Measure	Average Annual Savings (GWh)
LED (Interior)	11	LED (Interior)	1.3
Heat Pumps	0.67	Heat Pumps	0.94
HVAC Control	0.61	HVAC Control	0.62
HVAC VFD	0.58	HVAC VFD	0.60
LED (Exterior)	0.52	New Construction	0.53
Low Flow Fixtures	0.35	RCx-SEM	0.51
RCx-SEM	0.30	Food Services	0.37
New Construction	0.26	Low Flow Fixtures	0.35
Lighting Controls (Interior)	0.26	HVAC Equipment	0.30
Food Services	0.18	Insulation	0.18

Table 3-4. Commercial Top 10 Efficiency Measures by Total Lifetime Savings: Mid Program Scenario 2020-2034 Under Mid Rates

Measure	Sum of Total Lifetime Savings (GWh)
LED (Interior)	867
New Construction	296
Heat Pumps	181
HVAC VFD	133
HVAC Control	94
RCx-SEM	89
Insulation	67
HVAC Equipment	60
Food Services	48
Low Flow Fixtures	39

A breakdown of commercial average annual savings by end-use[30] is presented below (**Figure 3-10**) followed by lifetime savings (**Figure 3-11**), for comparison purposes.

Figure 3-10. Commercial Annual Electricity Savings by End Use (GWh): Mid Scenario, 2020-2024 (left) and 2025-2034 (right) Under Mid Rates

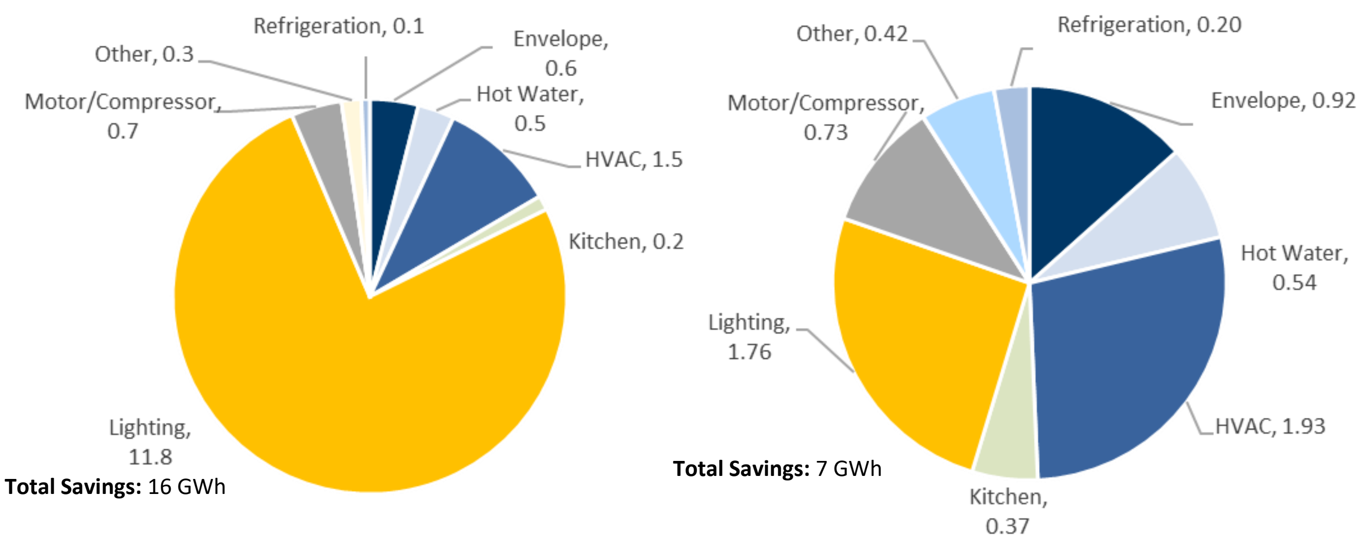
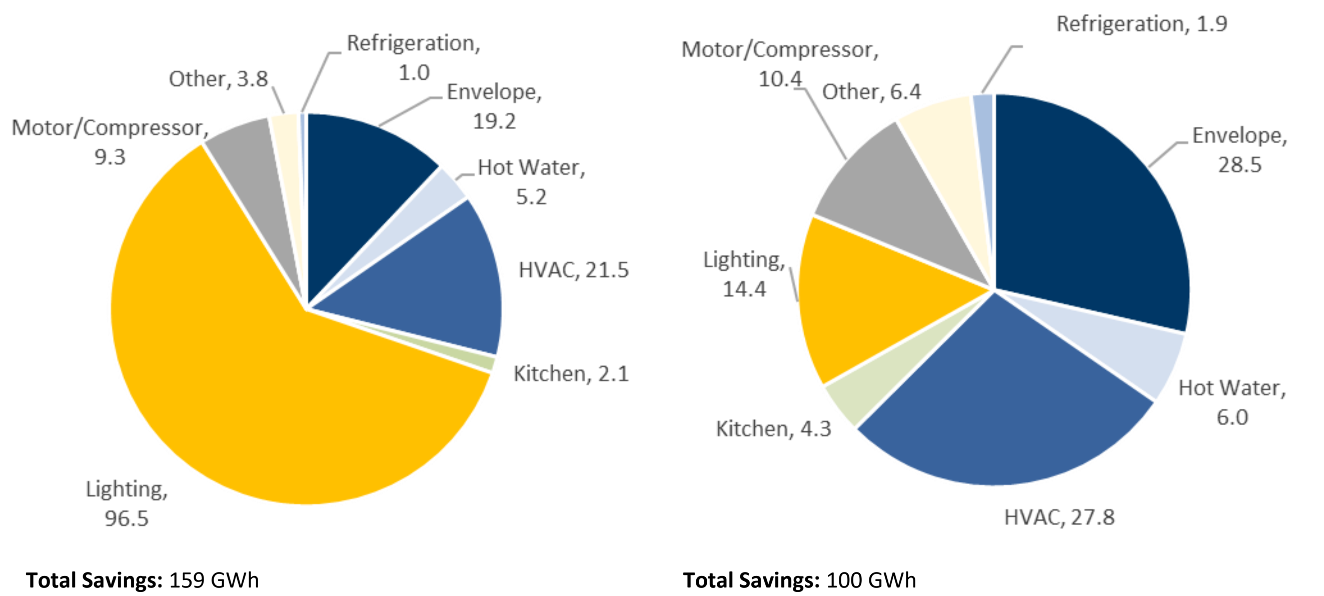


Figure 3-11. Commercial Lifetime Electricity Savings by End Use (GWh): Mid Scenario, 2020-2024 (left) and 2025-2034 (right) Under Mid Rates



[30] A complete list of the measures included within each end use is provided in Appendix E.

From these results, the following observations can be made:

- **Commercial lighting savings dominate in the initial years, but are expected to decline by over 85% in the later years of the study period.** As in the residential sector, the loss of lighting measures due to future EISA lighting standards causes a steep decline in savings. However, LED replacement of lighting equipment not targeted by the standards, such as fluorescent tubes, high bay fixtures and exterior lights, still provide important savings in the later years of the study.
- **HVAC measures presents a leading opportunity for the commercial sector over study period.** With four measures in the top 10 in the latter study years (HVAC Control, HVAC VFD, HVAC Equipment and Heat Pumps), the HVAC end-use shows the second most potential for program savings, starting after EISA standards come into effect (2023), and as a result also shows the second greatest potential in terms of lifetime savings during the later years of the study period (2025-2034). This may justify focusing CDM efforts on this end-use.
- **Envelope measures offer substantial lifetime savings:** While envelope measures do not show up in the top ten annual savings lists, the end-use breakdowns show that envelope savings offer substantial savings over the study period, due to their long EULs compare to other measures.
- **Recommissioning and Strategic Energy Management (RCx-SEM) is a top measure throughout the study period:** As electricity prices continue to rise, and many lighting measures drop out of the potential, the importance of RCx-SEM grows in importance for the commercial sector.
- **While LEED and Net-Zero-Ready New Construction measures offer too few annual savings in the initial years, they emerge as a top 10 measure in the later years, and offer the second highest lifetime savings overall:** The extremely long EUL of new construction measures (35 years) allows them to deliver significant lifetime savings.

INDUSTRIAL CUSTOMER END-USE BREAKDOWN AND TOP SAVINGS MEASURES

This section presents a breakdown of industrial savings opportunities (**excluding Large Industrial segment savings**[31]) by end-use and lists the top-saving measures under the Mid program scenario, applying the Mid-rates case. Both the end-use breakdown and the summary of top measures are quantified using averages of annual program savings for the initial five-year period (2020-2024), as well as the average over the later ten-year period (2025-2034). Lifetime savings are presented by end-use and for each of the top measures to provide further context concerning the persistence of savings.

The top electrical savings measures in the Industrial sector are presented below (**Table 3-5**). They are ranked by the average annual savings, and observation of the table shows an important difference in the ranking on an annual savings basis as compared to the lifetime savings basis. Presenting the measure lifetime savings helps to illustrate which savings offer the most long-term benefits, even after an incentive program may be retired. In

[31] Includes savings from Small and Medium Industrials, Fishing and Manufacturing, but excludes savings from Large Industrials which were analysed through a top-down approach and no end-use or equipment saturation data was available.

the following table, the top industrial savings measures by total lifetime savings over the full study period are provided (**Table 3-6**).

Table 3-5. Industrial Top 10 Efficiency Measures: Mid Scenario, 2020-2024 and 2025-2034 Under Mid Rates

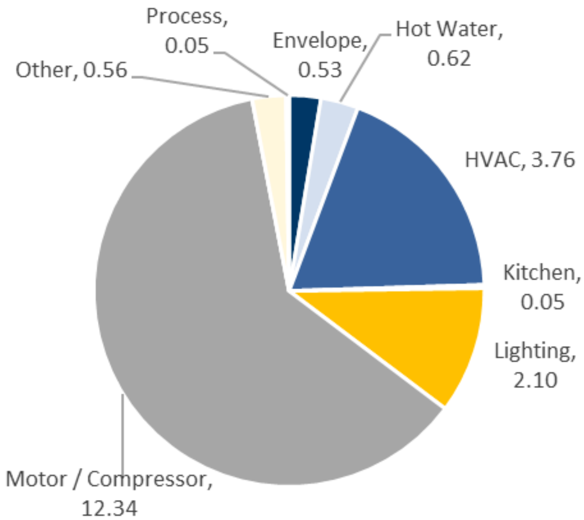
2020-2024		2025-2034	
Measure	**Average Annual Savings (GWh)**	**Measure**	**Average Annual Savings (GWh)**
Motor Controls	0.65	**Motor Controls**	0.69
LED (Interior)	0.28	**Motor/Compressor**	0.11
HVAC Control	0.086	**Heat Pumps**	0.11
Heat Pumps	0.066	**HVAC Control**	0.090
Low Flow Fixtures	0.064	**RCx-SEM**	0.086
HVAC VFD	0.063	**LED (Interior)**	0.068
Motor/Compressor	0.056	**HVAC VFD**	0.066
RCx-SEM	0.049	**Low Flow Fixtures**	0.064
Refrigeration Heat Recovery	0.038	**Refrigeration Heat Recovery**	0.040
Insulation	0.026	**Insulation**	0.027

Table 3-6. Industrial Top 10 Efficiency Measures by Total Lifetime Savings: Mid Program Scenario Under Mid Rates

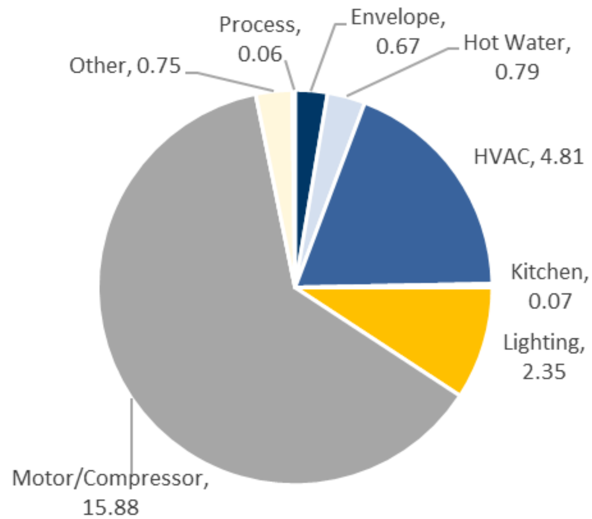
Measure	Sum of Total Lifetime Savings (GWh)
Motor Controls	150
LED (Interior)	21
Heat Pumps	20
Motor/Compressor	18
RCx-SEM	15
HVAC VFD	15
HVAC Control	13
Insulation	9.9
Refrigeration Heat Recovery	8.7
Low Flow Fixtures	7.3

A breakdown of industrial average annual savings by end-use is presented below (**Figure 3-12**) followed by lifetime savings (**Figure 3-13**), for comparison purposes.

Figure 3-12. Industrial Annual Electricity Savings by End Use (GWh): Mid Scenario, 2020-2024 (left) and 2025-2034 (right) Under Mid Rates

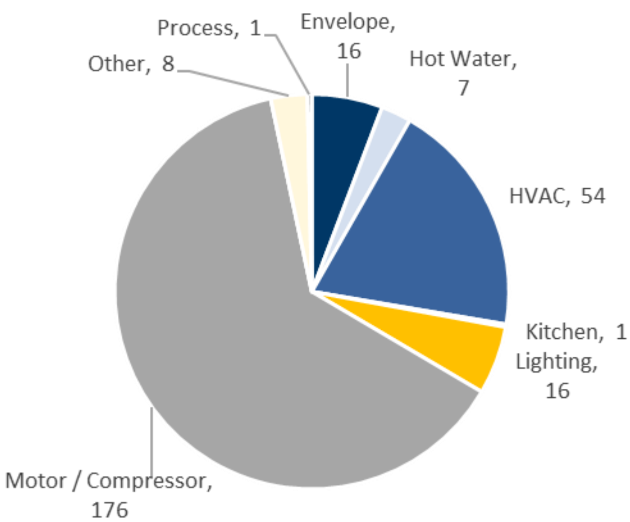


Total Savings: 20 GWh

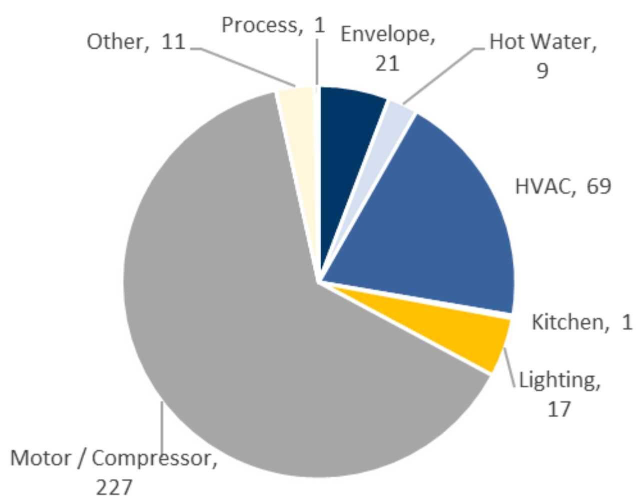


Total Savings: 25 GWh

Figure 3-13. Industrial Lifetime Electricity Savings by End Use (GWh): Mid Scenario, 2020-2024 (left) and 2025-2034 (right) Under Mid Rates



Total Savings: 279 GWh



Total Savings: 356 GWh

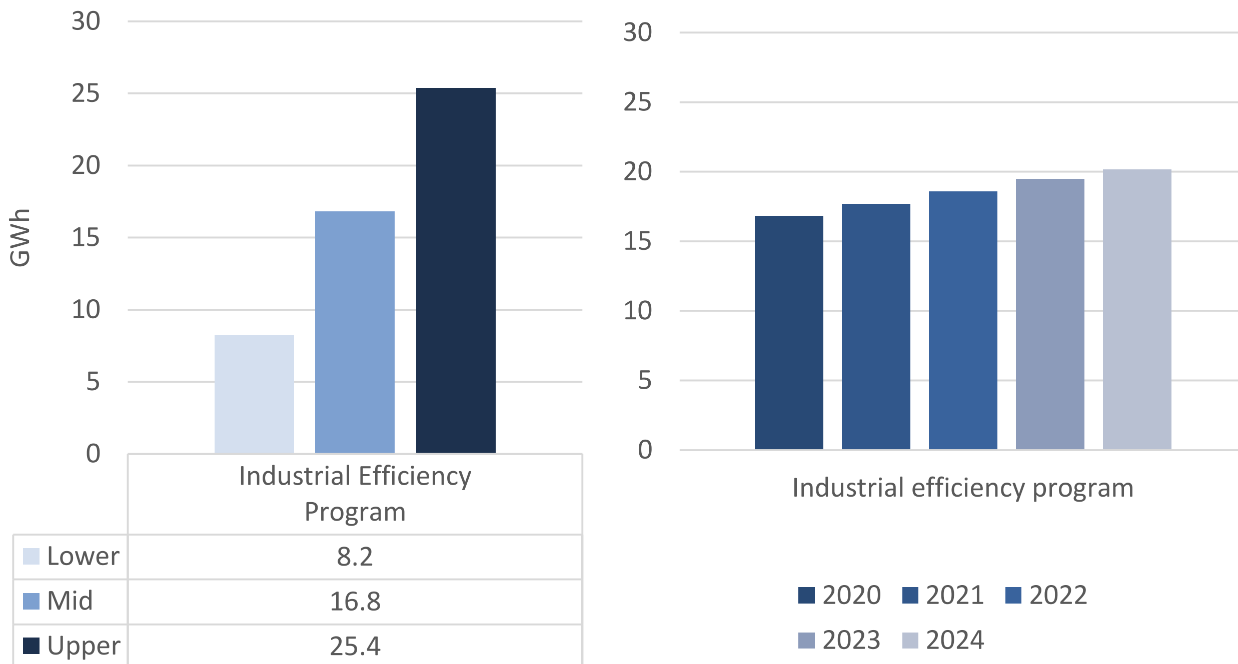
From these results, the following observations can be made:

- **Motors and Compressors dominate the industrial savings over the whole study period on both annual and lifetime terms**: Motor controls and efficient motors offer substantial savings opportunities and are predominant in industrial processes. Although not assessed in this study, presumably these measures would also offer substantial savings potential in the large Industrial segment.
- **HVAC measures present an important opportunity for the industrial sector over the study period.** Efficient heating and ventilation measures also offer significant opportunities in the industrial sector, given the number of facilities that operate year-round and have high annual hours of heating demand.
- **Industrial lighting savings are significant throughout the study period:** Industrial lighting uses few A-Lamp or Reflector bulbs, instead it applies more high-bay and linear lighting, neither of which are impacted by the projected lighting standards updates in 2023 and 2025.

INDUSTRIAL EFFICIENCY PROGRAM

Below, Industrial Efficiency Program savings for large industrial customers are presented under each program scenario for 2020 under the Mid-rates case **(Figure 3-14**) for the IIC and LAB systems collectively. The evolution of the annual savings over the initial five years for the Mid scenario (2020-2024) are also presented. This program covers Hydro's six transmission-level industrial customers which were treated outside of the DEEP model through a top-down analysis (see Appendix E for further details). The other Industrial customer segments savings are captured under the Business Efficiency Program.

Figure 3-14. Comparison of Industrial Efficiency Program Savings (Left – 2020) and Program Savings Evolution (Right – Mid Scenario) Under Mid Rates



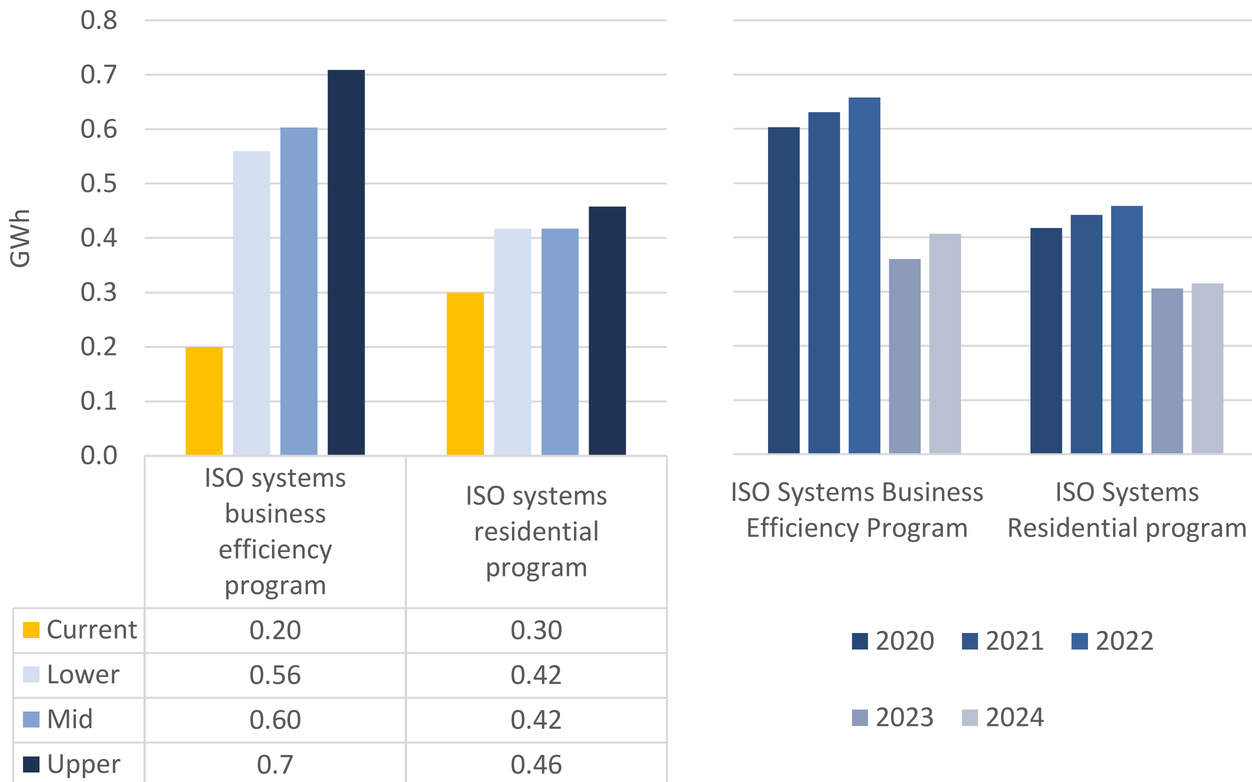
Observation of the above figure reveals the following:

- **Large Industrial program could dominate industrial savings opportunities:** Given the relative size of the energy demand from the six transmission-level customers to the other industrial segments, it is logical that these facilities would offer the most savings opportunities. Unfortunately, the top-down analysis performed for this segment does not provide details on the measures and end-uses that offer the greatest opportunities. Deeper exploration of current energy use at these facilities, and the efficiency performance of installed equipment may prove beneficial for pursuing savings in this important segment.
- **The Industrial programs exhibit steady growth in the initial study years:** The Utilities have offered industrial programs for the past few years, with little uptake, as a result there could be an increase in the savings potentials if the industrial programs begin to gain traction starting in 2020.

ISOLATED SYSTEM PROGRAMS

Below, current ISO system program savings[32] are presented alongside modeled savings under each program scenario for 2020 under the Mid-rates case (**Figure 3-15**). Current values are compared for the first year of the study (2020) as CDM program numbers are not available for later years. The program savings potentials for the initial five years (2020-2024) are also presented to show expected program savings evolutions.

Figure 3-15. Comparison of Isolated Program Savings (Left - 2020) and Program Savings Evolution (Right – Mid Scenario) Under Mid Rates



Observation of the above charts show that the residential program is expected to closely match past program results. However, the commercial program shows the potential for a notable jump in savings. Discussion with NL Hydro indicates that this is well recognized and new enabling strategies are currently being employed to increase savings from the ISO system Business Efficiency Program.

Moreover, the drop in savings for both the commercial and residential programs in 2023 the above figure indicates that much of these savings stem from A-Lamps, which are expected to be subject to new standards starting in 2023.

[32] Current Program savings are derived from recent CDM program evaluation reports or the 2016-2020 Energy Conservation Plan (2015, NL Hydro and NF Power) using 2019 planned savings where recent evaluations were not available.

END-USE SAVINGS AND TOP-10 MEASURES

This section presents a list of the top-saving measures in the ISO systems for both the residential and commercial sectors. The top electrical savings measures in the residential and commercial sectors are presented in the tables below (**Table 3-7** and **Table 3-8**). They are ranked by the average annual savings, and observation of the table shows an important difference in the ranking on a lifetime savings basis. The top residential and commercial savings measures ranked by total lifetime savings over the full study period are also provided (**Table 3-9**).

Table 3-7. ISO System Residential Top 10 Efficiency Measures: Mid Scenario 2020-2024 and 2025-2034 Under Mid Rates

2020-2024		2025-2034	
Measure	**Average Annual Savings (GWh)**	**Measure**	**Average Annual Savings (GWh)**
LED (Interior)	0.092	**ENERGY STAR Clothes Dryer**	0.037
Insulation	0.038	**Advanced Smart Strips**	0.024
Advanced Smart Strips	0.038	**Insulation**	0.019
Low Flow Shower Head	0.032	**ENERGY STAR Refrigerators**	0.017
Lighting Controls (Interior)	0.025	**Low Flow Shower Head**	0.013
Thermostats	0.023	**Efficient Windows**	0.012
Freezer Recycling	0.022	**Lighting Controls (Interior)**	0.011
Refrigerator Recycling	0.021	**Thermostats**	0.010
ENERGY START Clothes Dryer	0.020	**Faucet Aerators**	0.007
Faucet Aerators	0.020	**New Construction**	0.006

Table 3-8. ISO System Top 10 Commercial Efficiency Measures: Mid Scenario, 2020-2024 and 2025-2034 Under Mid Rates

2020-2024		2025-2034	
Measure	**Average Annual Savings (GWh)**	**Measure**	**Average Annual Savings (GWh)**
LED (Interior)	0.245	**LED (Interior)**	0.063
LED (Exterior)	0.040	**Motor/Compressor**	0.022
Motor/Compressor	0.017	**LED (Exterior)**	0.018
RCx-SEM	0.013	**RCx-SEM**	0.017
Lighting Controls (Interior)	0.010	**Lighting Controls (Interior)**	0.007
Food Services	0.002	**Food Services**	0.003
Air Sealing	0.002	**Air Sealing**	0.002
HVAC Control	0.002	**HVAC Control**	0.002
Insulation	0.001	**Faucet Aerators**	0.001
Faucet Aerators	0.001	**Insulation**	0.001

From these results, the following observations can be made:

- **Lighting measures dominate both commercial and residential sectors in the ISO system:** As noted, in the next five years lighting measures offer an important savings opportunity in the ISO system.
- **There is a wide diversity of measures in the top savings list, which is a result of almost all measures passing the cost-effective screen for the ISO system:** while customer prices are subsidized, the avoided costs of generation are extremely high in the ISO system, which makes almost all measure pass the TRC screen, making them available for inclusion in CDM programs.

Table 3-9. ISO System Top 10 Efficiency Measures by Lifetime Savings: Mid Scenario, 2020-2024 Under Mid Rates

RESIDENTIAL		COMMERCIAL	
Measure	**Sum of Total Lifetime Savings (GWh)**	**Measure**	**Sum of Total Lifetime Savings (GWh)**
Insulation	0.68	**LED (Interior)**	2.4
ENERGY STAR Clothes Dryer	0.40	**LED (Exterior)**	0.26
LED (Interior)	0.32	**Motor/Compressor**	0.23
Low Flow Shower Head	0.23	**RCx-SEM**	0.19
Advanced Smart Strips	0.20	**Lighting Controls (Interior)**	0.090
Efficient Windows	0.18	**Insulation**	0.030
Thermostats	0.18	**Air Sealing**	0.028
Lighting Controls (Interior)	0.17	**Food Services**	0.025
ENERGY STAR Refrigerators, Most Efficient	0.16	**HVAC Control**	0.017
Faucet Aerators	0.14	**Motor Controls**	0.016

CDM PROGRAMS: KEY TAKE-AWAYS

Based on the results presented in this chapter, the following key take-aways emerge from the CDM Program potential analysis:

- **CDM Program savings in the initial five-year period (2020-2024) range from 0.5% to 1.1% of sales under the Lower to Upper Scenarios (for the IIC + LAB systems):** These ranges put the NL Utility CDM programs squarely in the range of savings being achieved by other Canadian utilities. The Lower program scenario potential would correspond to current CDM program savings, but with a marginal increase in some programs stemming from the expected increase in customer rates as the Muskrat Falls generation facility comes on line. Savings in this period are dominated by substantial lighting savings when summed across all sectors, a trend that is particularly strong in the ISO system.

- **Annual savings potentials are expected to drop by nearly 50% in all systems after 2024:** This is driven by standards changes in lighting primarily, that eliminate savings from A-Lamps and Reflectors (specialty bulbs) which are projected to take effect, or lead to market transformation to LEDs, in 2023 and 2025. Once residential and standard commercial lighting has been removed from the programs, annual savings drop to a lower level. Commercial lighting savings dominate in the initial years, but are expected to decline by over 85% during the study period.

- **Residential sector annual savings are highest for Home Energy Reports, but envelope measures offer the greatest lifetime saving:** As much as 50% of annual savings come from Home Energy Report However, this program offers limited lifetime savings, due to its 1-year EUL. Envelope measures provide significant annual savings and almost half of all lifetime savings by the end of the study period. Contrary to the Home Energy Reports, envelope measures (with insulation, air sealing and efficient windows leading the group) contribute slightly more than 20% of annual program savings by the end of the study, but due to their long EULs they generate close to half of the overall lifetime savings. These results demonstrate the value of investing in barrier and cost reducing efforts to promote envelope upgrades in new and existing homes in Newfoundland and Labrador.

- **Commercial sector savings are initially dominated by lighting, but in the later years HVAC measures presents a leading opportunity.** With four measures in the top 10 in the latter study year (HVAC Control, HVAC VFD, HVAC Equipment and Heat Pumps), the HVAC end-use shows the second most potential for program savings, starting after EISA standards come into effect (2023). It also has the greatest potential in terms of lifetime savings during the entire study period. This may justify focusing CDM efforts on this end-use.

- **Industrial sector savings are driven by the large industrial segment. Motors and compressor measures related to processes dominate the program savings in all periods.** The industrial sector also offers notable lighting savings; as most industrial lighting is not impacted by the new EISA lighting standards. Finally, HVAC measures also offer notable savings for industrial facilities where they have high annual hours of use (24-hour operation or shift work).

4. DEMAND RESPONSE POTENTIAL

The Demand Response (DR) potential was assessed by analysing the ability for electricity rate designs, equipment controls and industrial and commercial curtailment to reduce the annual peak demand in each of the two interconnected systems (IIC and LAB). Because the IIC system includes 90% of all NL electricity customers, demand response programs were first assessed on this system, and then programs that offered significant potential were assessed for expansion to the LAB system customers to determine the impact on that system's annual peak.

To evaluate DR program potential, a standard peak day, which was identified and adjusted to account for load growth and efficiency program impacts over the study period, was created based on NL Utilities' historical hourly annual load curves. The DR potential was also analysed across five years of NL Utilities' historical hourly annual load curves to simulate year-long measure deployment. To ensure that the combined achievable potential results were truly additive in their ability to reduce annual peak loads, combinations of programs were assessed against each system's annual hourly load curve to capture inter-program interactions that could effect the net impact of each program. Further details of this approach are provided in Appendix B.

There are a few key differences between the DR potential assessment and the efficiency potential assessment that are important when reviewing the results:

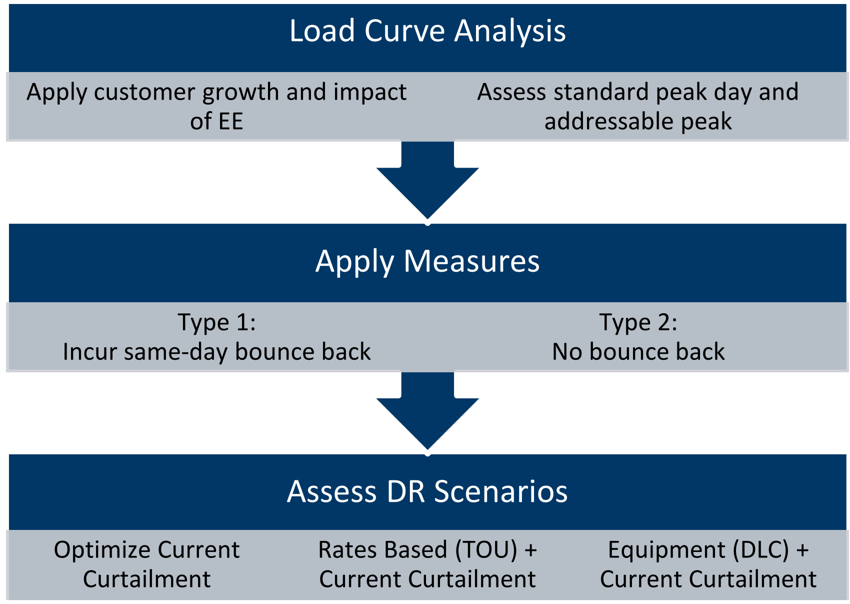
- **The technical and economic potentials were assessed for each measure individually.** Because measures can interact with each-other's ability to create a net reduction in the utility load peak and demand curve profile, technical and economic potentials for DR measures are not considered to be additive, and are therefore not presented in aggregate in this report.
- **The three achievable DR scenario tests represent three program strategies** for actively reducing demand: optimizing current curtailment, expanding to time of use rates, or adding called equipment controls (manual or direct by utility).
- **For each period, the DR potential is expressed as the potential for programs that began in that year**. Unlike many efficiency programs, the DR peak savings only persist as long as the program is active. Factors, such as program roll-out and recruitment of participants may affect the actual achievable peak impacts, especially for newly offered programs.

OVERVIEW OF DEMAND RESPONSE MODELLING APPROACH

Figure 4-1 below presents an overview of the analysis steps applied to assess the DR potential in this study. For each step, system-specific inputs were identified and incorporated into the model. Key to this assessment of the DR potential is the treatment and consideration of the system hourly load curve on the peak day, as well as over the entire years (using historical 8,760 hourly peak load curves). This allows the model to assess the impact of each measure or program on the utility load curve considering key constraints, and the interactive effects among DR programs.

As will be presented in the following chapter, this may lead in some cases to results that are contrary to initial expectations, especially when DR programs such as time-of-use (TOU) rates or equipment direct load control (DLC) are looked at only from the perspective of how they may impact individual customer peak loads, and not the overall interaction with the utility load curve and other DR programs. A more detailed description of the DR modeling approach applied in this study can be found in Appendix B, and Appendix E.

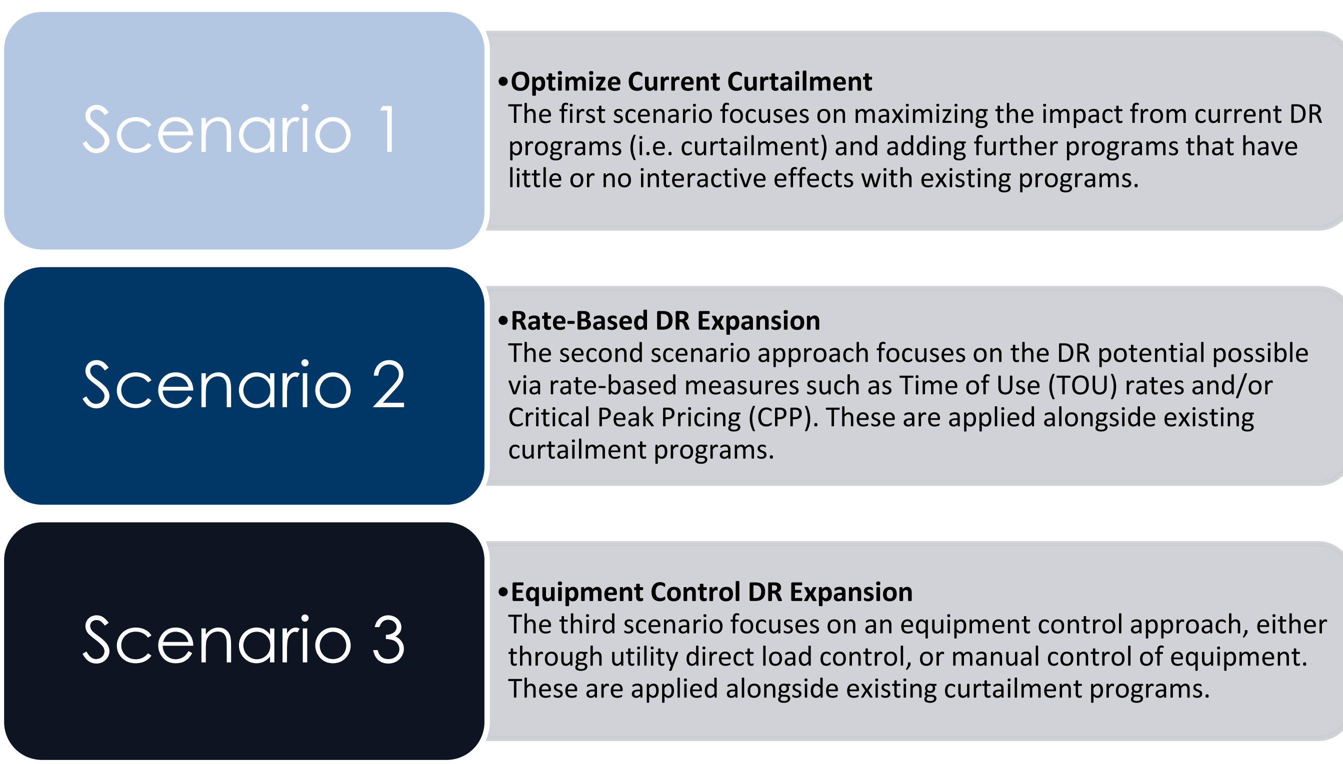
Figure 4-1. Demand Response Potential Assessment Approach



DEMAND RESPONSE SCENARIOS

The study assessed the DR potential under three scenarios corresponding to varied DR approaches or strategies. These scenarios deliver varying benefits covering a range of peak demand impacts. Further details on the specific programs and the related inputs modeled for each scenario are presented in Appendix E and Appendix F.

Figure 4-2. Demand Response Program Scenarios



LOAD CURVE ANALYSIS

The first step in the DR potential analysis was to identify the standard peak day for each of the interconnected systems (IIC and LAB), and apply load growth and efficiency impacts to develop a projection of the peak day 24-hour load curve for each year in the study period. The standard peak day load curve provides a representative load shape that was then used to characterize measures and assess the measure-specific peak demand reduction potentials at the technical and economic potential levels. Achievable peak demand reduction potentials were further verified against five-years of historical hourly load data to assess the impact of annual DR measure deployment constraints.

IIC SYSTEM

The standard peak day for the IIC system was identified as the 97.5th percentile peak load, based on taking the load shape from the top ten peak days in each of five years of historical hourly load data provided by the NL Utilities (**Figure 4-3**). The standard peak day curve was then adjusted to match the projected annual peak demand in each year, as provided by the utilities. **Table 4-1** provides key metrics to describe the peak day shape from a DR potential perspective.

Figure 4-3. IIC Standard Peak Day

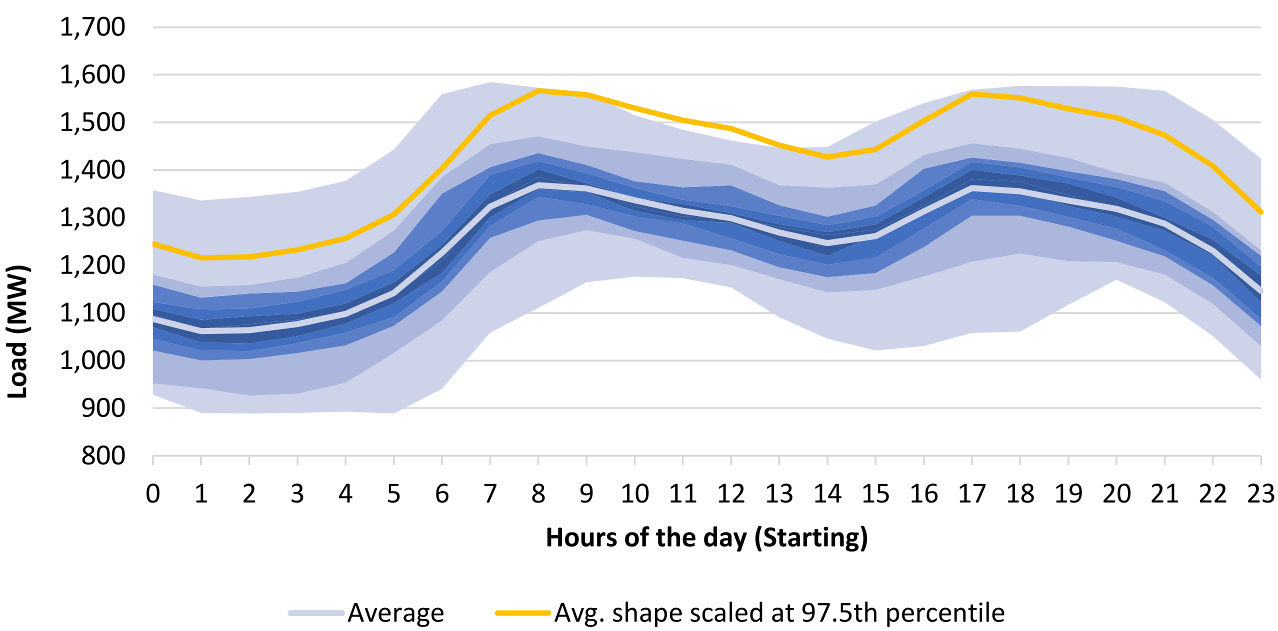


Table 4-1. IIC Standard Peak Day Key Metrics

Peak hours	Peak to Average Difference	Peak to Average Ratio	Number of hours within 10% of peak	Primary End-Use
Morning 7:00 – 10:59 **Evening** 16:00 – 20:59	141 MW	1.10	14 hours	**Morning:** Heating – 67% **Evening:** Heating – 54%

It was found that the IIC system has two extended peaks, which are driven predominantly by residential heating. The narrow margin between the peak and the daily average load indicates that measures with significant bounce-back or pre-charge effects will likely have limited potential to reduce the peak, as they risk creating new peaks by shifting load from one hour to another.

LAB SYSTEM

The standard peak day for the LAB system was identified as the 97.5th percentile peak load, based on taking the load shape from the top ten peak days in each of five years of historical hourly load data provided by the NL Utilities (**Figure 4-4**). The standard peak day curve was then adjusted to match the projected annual peak demand in each year, as provided by the utilities. **Table 4-2** provides key metrics to describe the peak day shape from a DR potential perspective.

Figure 4-4. LAB Standard Peak Day

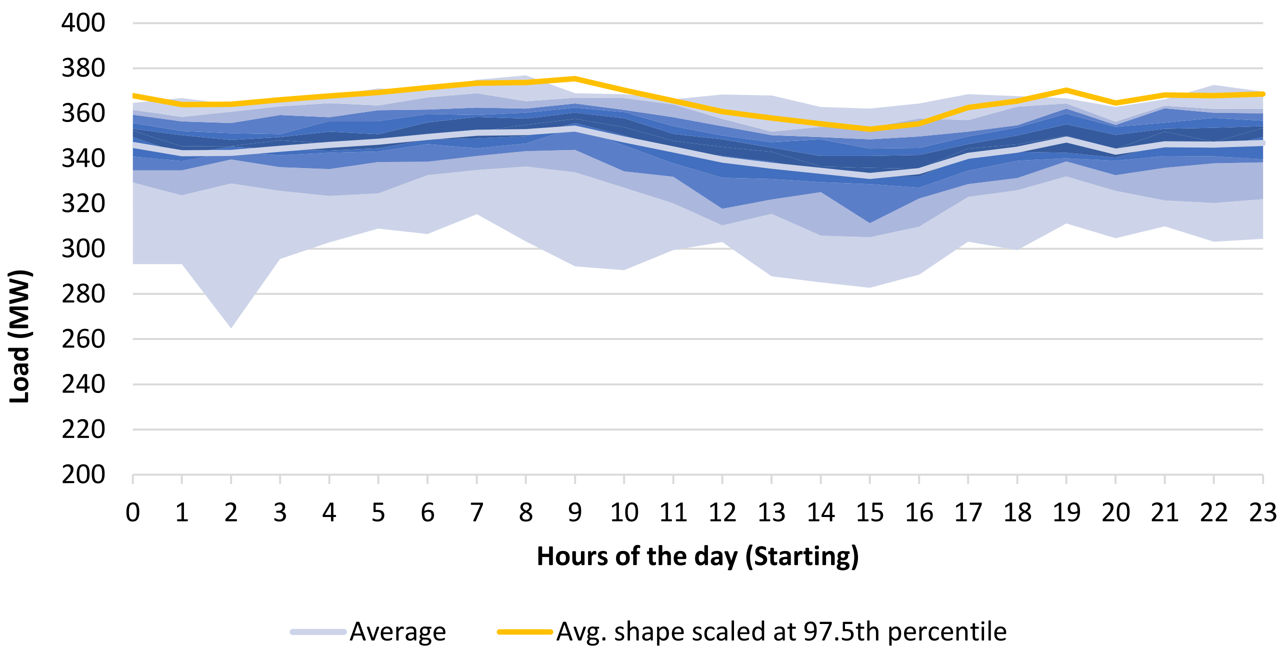


Table 4-2. LAB Standard Peak Day Key Metrics

Peak hours	Peak to Average Difference	Peak to Average Ratio	Number of hours within 10% of peak	Primary End-Use
Morning: 7:00 – 9:59 **Evening:** 18:00 – 20:59	10 MW	1.03	24 hours	**Morning:** Industrial – 52% **Evening:** Industrial – 56%

The results show that LAB system nearly as a perfectly flat load shape. This would be expected to greatly limit measures with bounce-back or pre-charge effects as they risk creating new peaks by shifting load from one hour to another. Type 2 measures, with no bounce-back or pre-charge are more adapted to LAB system.

INDIVIDUAL MEASURE IMPACTS

The analysis applied a range of existing curtailment and new DR programs, assessing the ability of each to address the annual peak on their own, and then assessed the achievable potential in each achievable scenario program grouping to determine the combined effect of each set of programs on the utility load curve. A description of each individual program assessed follows. More details on the specific measures and input assumptions can be found in Appendix E.

It is important to note that in this section all potentials presented are for individual measures when applied to each system load curve. Measures that delivered notable peak load reductions individually were then retained and applied in the achievable scenario analysis to determine their true achievable potential when interacting with other programs and measure combinations, the results of which are presented later in this Chapter.

INDUSTRIAL CURTAILMENT

The NL Utilities have identified a significant amount of industrial curtailment potential through the large industrial customers. This is comprised of self-generation capacity, as well as load curtailment that can be engaged when a DR event is called by the NL Utilities. Collectively the NL Utilities have 133MW of industrial curtailment capacity under contract, which represents 8% of each system peak. A further 18MW of potential has been identified by the Utilities but is not yet included under the existing contracts. A summary of the industrial curtailment potential is presented below in **Table 4-3** below.

Table 4-3. Large industrial under curtailment program

Provider (System)	Contracted Capacity	Assessed Potential	Constraints to Curtailment Contract
Corner Brook (IIC)	105 MW	105 MW	*Period:* 4 to 6 hours, *Request:* 2 per day max, 60 per year, *Total period:* 250 h
Vale – Generation (IIC)	8 MW	8 MW	*Period:* up to 6 hours, *Request:* 2 per day max, 20 per year, *Total period:* 100 h
Vale – Curtailment (IIC)	12 MW	12 MW	*Period:* 3 to 6 hours, *Request:* 2 per day max, 10 per year, *Total period:* 50 h
IOC (LAB)	30 MW	8 MW	No yet completely defined. Corner Brook constraints were used for the purpose of this analysis.
Total (Large Industrials)	**155 MW**	**133MW**	133 MW currently enrolled
Small and Medium Industrials (IIC)	0 MW	14–17 MW	Requires expansion of the industrial curtailment program to these customers.
Small and Medium Industrials (LAB)	0 MW	2–3 MW	Requires expansion of the industrial curtailment program to these customers.

After adjusting the Utility load curves to account for the impact of efficiency programs, and assessing the industrial curtailment in the IIC system over a 5-year period (based on historical 8,760 hour load curve) and accounting for the contract constraints (see **Table 4-3**), it was found that the full 125MW of contracted Industrial Curtailment is directly translated into Achievable Potential.

For the LAB system, when the 30MW Industrial Curtailment contract was applied over a 5-year set of hourly loads, the analysis revealed that the net impact drops to 8MW due to the contract constrains that lead to new peaks occurring at times when the Industrial Curtailment is not available. Further details of this analysis are provided in Appendix F.

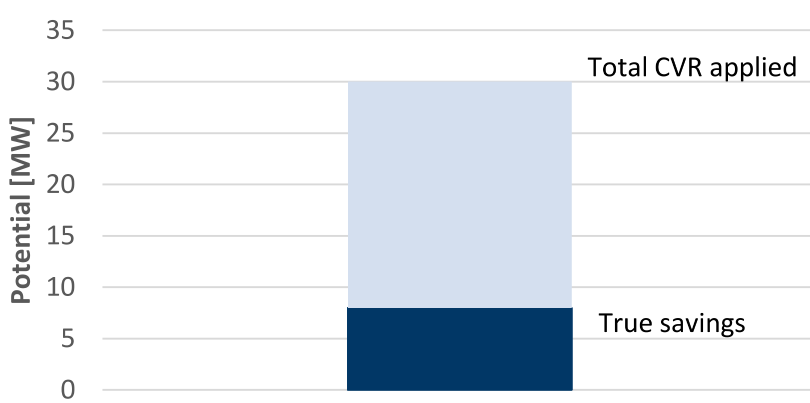
The analysis also explored the potential for expanding industrial curtailment to more small and medium industrial customers would allow a potential increase in demand savings by 16–20 MW. Small and medium industrial curtailment was assumed to focus on a 3-6 hour interruption window with no demand rebound or production shifted to weekends.

CONSERVATION VOLTAGE REDUCTION

NF Power currently reports having the capacity to apply 30MW of conservation voltage reduction (CVR) on the IIC system.[33] The impact of the applied CVR varies depending on the mix of loads within the system. To capture this effect, a CVR factor was calculated that relates the applied CVR capacity to the net load reduction on the system (the amount that persists after intermittent resistive loads have adjusted to the lowered system voltage).

Based on the mix of residential, commercial and industrial loads during the annual winter peak hour, a CVR factor of 0.27 was calculated to represent the CVR impact on the IIC system.[34] This results in 8MW of net CVR potential when 30MW are applied.

Figure 4-5. Conservation Voltage Reduction – Average winter savings



[33] NL Hydro does not currently have any CVR capacity on the LAB system.

[34] CVR factors were assessed from “Measuring the efficiency of voltage reduction at Hydro-Québec distribution”, S. Lefebvre ; G. Gaba ; A-O. Ba ; D. Asber ; A. Ricard ; C. Perreault ; D. Chartrand. IEEE, 2008. Further details found in Appendix E.

COMMERICAL CURTAILMENT

NF Power currently offers a commercial curtailment program that has 11 MW of potential currently enrolled. This is comprised primarily of back-up generators (BUGs), which makes up 10 MW of the total program capacity. One enrolled customer provides a further 1 MW of interruptible loads in their facility. Based on NL commercial end-use survey, 10% of commercial customers would likely have BUGs to supply, on average, 47% of their building load. This leads to a maximum technical potential of 15 MW for the IIC system. It was assumed for this analysis that the current 10 MW of BUGs enrolled represents the full achievable potential, since this portion falls outside of the commercial sector propensity curves applied to determine achievable potentials in the study. Further commercial curtailment was assessed in the model, specifically through manual or automated controls of HVAC and lighting systems in commercial facilities.

Because the questions concerning BUGs in the NL commercial end-use received only ten responses in the LAB system, it was judged to not be statistically representative. Instead, an assumption that 8% of commercial customers would likely have BUGs to supply the heating load of the building was used.[35] The LAB system shows a maximum potential of 3 MW. There was no modification to the maximum potential since there's no commercial curtailment program in place in Labrador.

RATE-BASED MEASURES

The NL Utilities do not currently offer a Time of Use (TOU) rate program or a Critical Peak Pricing (CPP) program. The analysis tested a range of TOU rate designs in the IIC systems, starting with the two-tier and three-tier models presented in the recent NL Hydro marginal cost study.[36] The TOU rates program was characterized as an opt-out program to maximize its potential impact, and various rate designs were assessed against the IIC system curve to determine the optimal TOU rate design to lower the annual peaks. TOU rates were designed to reduce the standard peak day load and were tested over 5 years of historical hourly load data to determine the net impact.

Ultimately a two-tier, 2:1 peak to off-peak TOU rate design, applied to both residential and commercial customers, was found to deliver the highest peak demand reduction potential on the IIC system, when applied in the absence of other DR programs and measures (**Figure 4-6**). The same TOU ratio is applied to both residential and commercial sectors. **Figure 4-6** presents this TOU rate structure as well as the normalized energy redistribution profiles from the TOU demand savings.

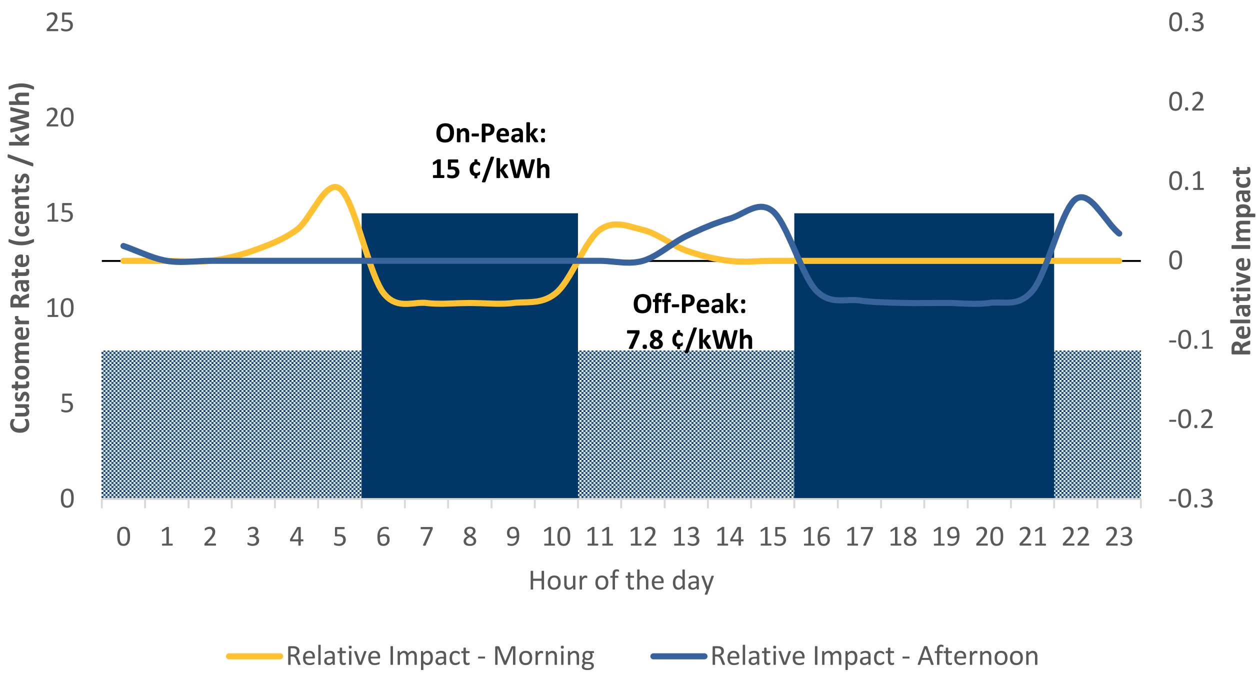
In the following TOU figures, bounce-back effects are indicated by the times that the yellow or blue impact lines cross into positive values, which implies an increase in the demand at those times. These account for the times when customers will use more electricity just prior to, or after, the high rates periods. Peak savings times are indicated when the yellow or blue line cross into negative values. These indicate times where customers would use less electricity than their habitual usage to avoid the peak rate periods.

---

[35] Source: "Commercial Building Energy Consumption Survey", 2012, U.S. Energy Information Agency

[36] Source: "Marginal Cost Study Update – 2018", Nov. 15, 2018, NL Hydro

Figure 4-6. Residential TOU Rate Design and Corresponding Demand Redistribution Effects

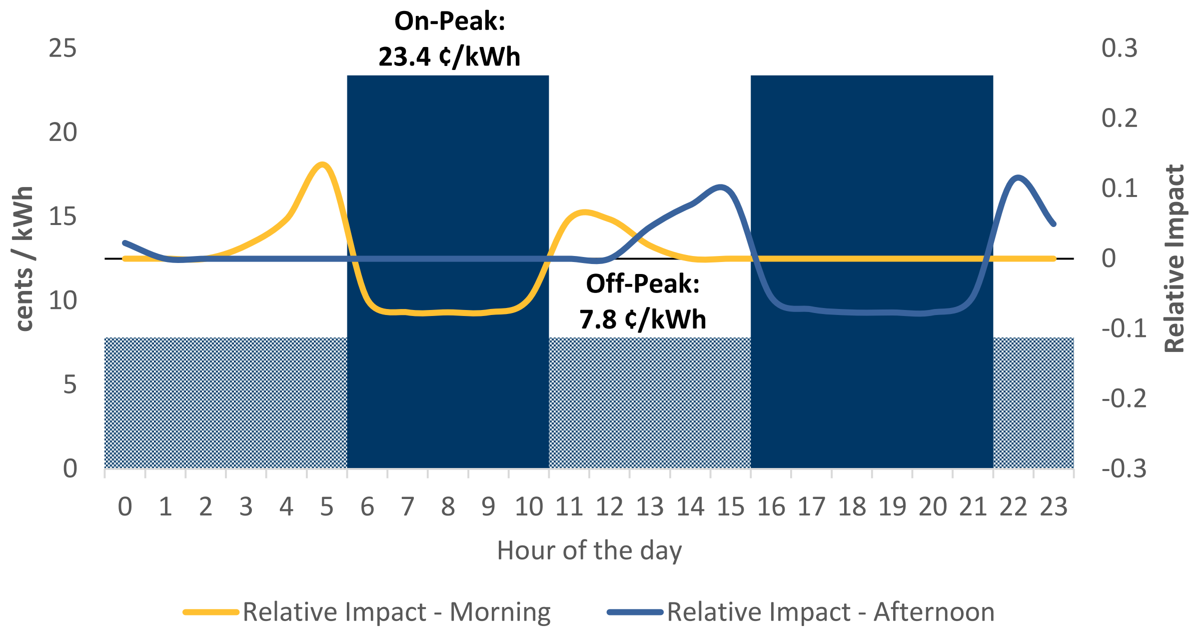


Note: The Residential TOU rate structures are shown here for illustrative purposes. The same on-to off peak ratios would apply to commercial customers applied to all the various commercial rate classes and tiers.

The two-tier 2:1 TOU Rate design was applied to both systems, and while it reduced the peak demand in the IIC by 14MW, it led to a net increase of 7 MW in the LAB system. Overall, the relatively flat peak day load shape in the IIC and LAB systems were an important factor that limited the TOU rates potential. As will be seen later, this impact was further exacerbated when it was found that the application of a TOU Rates program reduced the existing industrial curtailment program potential by more than the TOU rate potential reduction, thereby leading to a net increase in the annual peak. Details on this analysis can be found in Appendix F.

A CPP program was also modelled as it generally exhibits higher demand saving than TOU. The advantage of the CPP program over the TOU program is that it is applied only for specific DR event calls eliciting customer driven load reduction only when needed. On the other hand, TOU rates are applied consistently over the year which reshapes customer behaviour to reduce peak loads. However, for the IIC system it was found that a 3:1 CPP ratio (as presented in **Figure 4-7**) would increase peak demand by 16 MW. Therefore, this measure was not retained for further consideration in the study.

Figure 4-7. Residential CPP Rate Design and Corresponding Demand Redistribution Effects



EQUIPMENT CONTROL MEASURES

An extensive list of DR equipment control measures was considered for the Equipment Control programs (see Appendix E). From the initial list of equipment control measures, only a few were found to offer the potential for reducing the system load when assessed against the IIC and LAB peak day load curves. Given the high avoided costs for both IIC and LAB, most measures are cost-effective.

The analysis revealed that for both systems (IIC and LAB) the relatively flat system load shape on the peak day was a key limiting factor. As a result, the majority of measures tested, actually created new higher peaks. A handful of measures did provide a degree of peak load reduction, when run individually against the utility load curve. These are listed below (**Table 4-3)**.

Table 4-3. Effective Equipment Control Measures for IIC System: Economic Potential

RESIDENTIAL			COMMERCIAL		
Measure (End-Use Impact)	**IIC 2034 Potential (MW)**	**LAB 2034 Potential (MW)**	**Measure (End-Use Impact)**	**IIC 2034 Potential (MW)**	**LAB 2034 Potential (MW)**
Setpoint control (Heating)	25	3.5	Setpoint control (Educational – Heating)	2.7	0
Water Heaters (Domestic Hot Water)	26	3.5	Reduction of fresh air flow (HVAC Pump/Fans & Heating)	3.9	0
Clothes Dryer (Plug load)	20	2.0			

Overall, the analysis revealed that:

- **Any of the three residential-sector measures could potentially offer enough savings to sustain a program.** On the other hand, the savings from the commercial measures did not appear to be sufficient to build a new program but may offer potential if added under the existing Commercial Curtailment program. The IIC load shape allows for 26 MW of equipment control demand savings. LAB also show similar results, although with a lower demand saving potential of 4 MW.

- **However, Equipment Controls measures change the utility curve such that they significantly reduce the potential from the existing curtailment programs:** The impact of the equipment program on the utility curve creates peaks that cannot be as effectively addressed by the currently deployed industrial and commercial curtailment. Thus, the net benefit of the equipment controls program is greatly reduced or eliminated in most years, and as a result it does not appear that investing in the additional program infrastructure to offer equipment controls DR would be warranted, given that the same savings could be achieved using currently enrolled curtailment.

DUAL-FUEL HEATING

The potential for Dual Fuel heating was assessed by applying it to homes and businesses with existing central electric heating systems. This program entails installing a back-up oil heater in buildings with central electric heating, along with controls that allow the NL Utilities to switch the heating system from the electric to the oil-fired system during DR events. This measure does not exhibit any bounce-back effects, and was found to offer significant potential when applied against the utility load curves in both systems. Two program options were assessed, one that placed a constraint of 12 DR event calls per year, and one unconstrained option where the NL Utilities can call on the oil-fired heating systems as many times and for as much duration as needed to reduce peaks (**Table 4-4**). Dual-fuel potential is divided between the residential (43%) and commercial (57%) sectors.

Table 4-4. Dual-Fuel Heating Potential by System (2034)

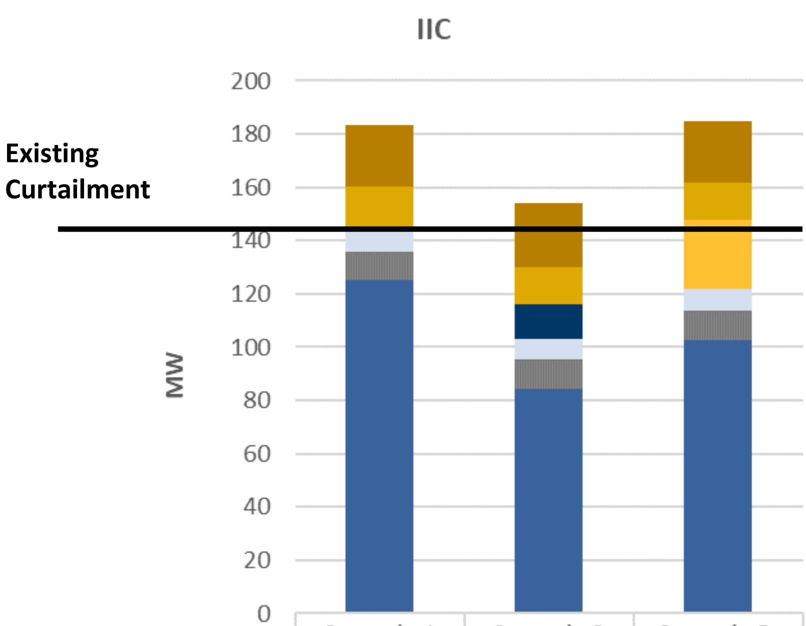
	Potential with Constraints	Unconstrained Potential
IIC Dual Fuel Potential	23 MW	72 MW
LAB Dual Fuel Potential	4.6 MW	14 MW

The constrained Dual-Fuel program potential was retained for further assessment in the achievable potential assessment, as it offers a balance between encouraging peak load reduction, without switching a significant portion of electric heating consumption to oil heating.

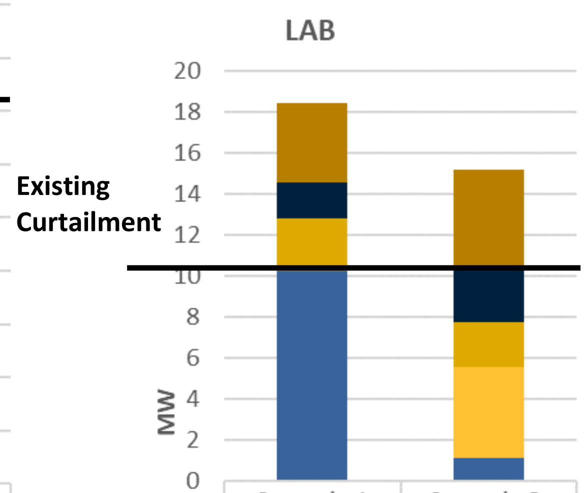
ACHIEVABLE POTENTIAL RESULTS

The overall achievable potential in each system is presented below (**Figure 4-8** and **Table 4-5**). It highlights each achievable scenarios' overall peak load reduction potential when all the constituent programs are assessed together against the utility load curve, accounting for the combined interactions among programs. A line indicating the potential from existing commercial and industrial curtailment and CVR (IIC only), is also indicated for comparison.

Figure 4-8. Demand Response Potential[37] (2034)



	Scenario 1	Scenario 2	Scenario 3
Dual-Fuel	23	24	23
Small/Med Industrials	16	14	14
Equipment	0	0	26
TOU	0	13	0
CVR	8	8	8
Commercial Curtailment	11	11	11
Large Industrials	125	84	103



	Scenario 1	Scenario 3
Dual-Fuel	4	5
BUGs	2	3
Small/Med Industrials	3	2
Equipment	0	4
Large Industrials	10	1

[37] Since dynamic rates have a negative impact on LAB system, Scenario 2 is not present in the LAB analysis. The following sections and Appendix F contain more details on dynamic rates and their impacts on LAB and IIC systems.

Table 4-5. Existing Curtailment and Scenarios Comparison (2034)

System	Existing potential	Scenario 1:	Scenario 2:	Scenario 3:
IIC	144	183	154	185
LAB	10	19	19[38]	15
Total	**154**	**202**	**173**	**200**

From the above results the following conclusions can be drawn:

- **Scenario 1 - Optimizing the Existing Curtailment is the most advantageous scenario for both systems:** Scenario 1 offers the most potential in almost all years for both IIC and LAB systems. The focus on the existing curtailment approaches carries the least degree of program complexity and cost when compared to scenarios 2 and 3 that would require adding the program infrastructure for TOU Rates, CPP and equipment direct load controls respectively.

- **In the IIC systems there is little benefit, or even a reduction in peak reduction benefits, by adding measures that incur significant bounce back effects:** Under Scenario 2 in the IIC system, the overall potential actually drops when the optimally designed TOU rates program is added to the mix of programs as it undermines the ability for the Industrial Curtailment program by creating new, choppier peaks in the load curve (further details on this analysis are provided in Appendix F). Scenario 3 in the IIC system does yield a marginally higher overall potential (2MW higher). However, this net increase is much smaller than the 26MW peak reduction from the Equipment Controls program, because the Equipment Controls program also undermines the Industrial Curtailment program potential.

- **In the LAB system focusing on the current Industrial Curtailment also offers the higher potential:** In the LAB system, the optimized two-tier, 2:1 TOU rate design led to a net increase on the peak when applied alone, and thus Scenario 2 was not assessed. When the Equipment Controls program was added, the shifted peaks once again undermined the ability of the Industrial Curtailment to reduce peak loads, resulting in an overall lowering of the peak demand reduction potential as compared to Scenario 1.

- **Industrial Curtailment provides the bulk of the peak reduction potential, and there is a great deal of potential already under contract. Further study is required to determine if adjusting the Industrial contracts may allow the Utilities to leverage TOU Rates, CPP or Equipment Controls Program Potentials:** Expanding industrial curtailment may offer potential to pursue further demand response. It is also important to note, that all Industrial Curtailment was applied in the analysis under the current contract constraints. Considering the apparent conflict between the TOU Rates, CPP and Equipment programs and the Industrial Curtailment, it may be possible to renegotiate the Industrial Curtailment contracts to cover more facilities, extend over longer periods of time, or allow for more events per year.

[38] Using best scenario (Scenario 1: Optimise Existing Curtailment) since TOU is not improving peak demand savings for LAB system.

With fewer constraints on the Industrial Curtailment, it may be possible for the TOU Rates, CPP and Equipment Controls program to add incremental peak demand reduction over and above the current program scenario potentials. The Utilities will explore this possibility in another study.

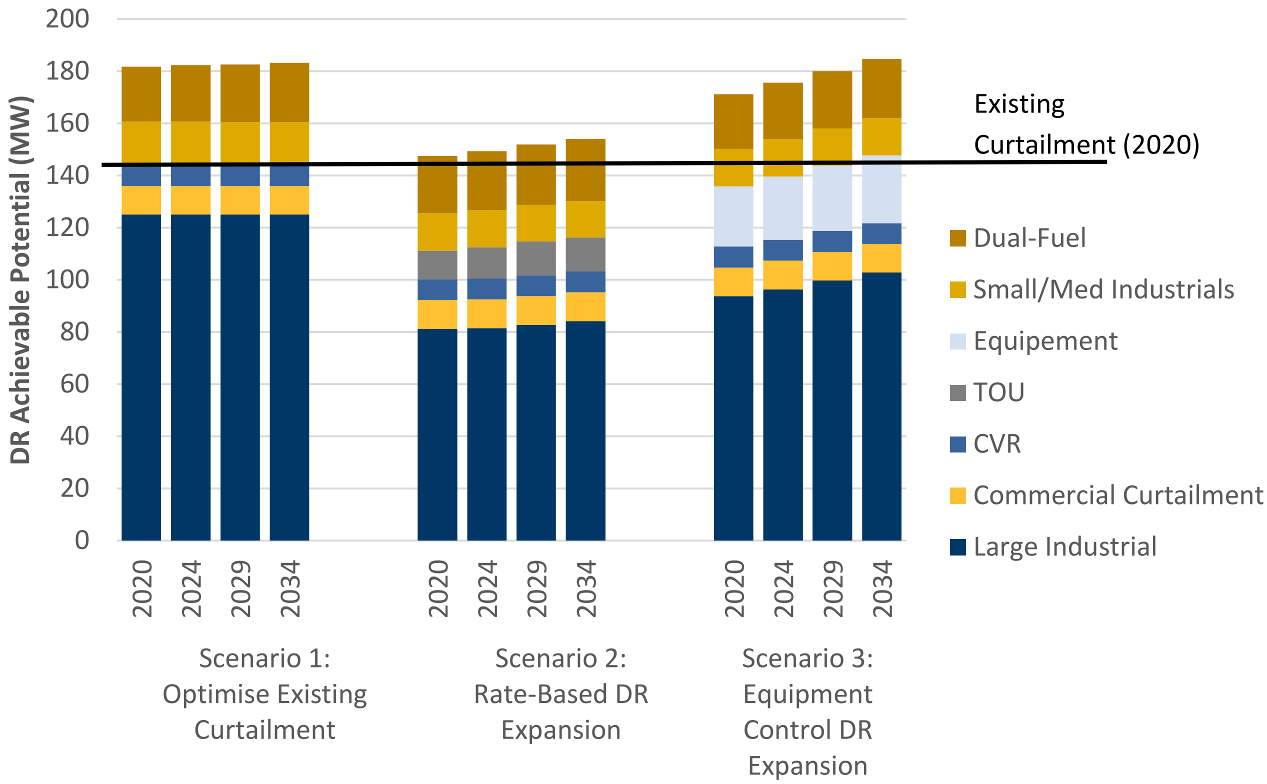
Additional DR Potential is Constrained by the Current DR Programs and Flat Utility Load Curve

Our analysis shows that NL's high avoided costs of capacity allow for many DR measures to be cost-effective when assessed individually. However, the flat utility load shape limits additional potential for any measures with rebound effects when they are run alongside existing curtailment program. This is because the current Industrial Curtailment contracts are generally constrained to 4-6 hour windows, twice a day, based on the current utility peak load profiles (morning and evening). When TOU Rates, CPP and Equipment Controls are added to the program mix, they tend to reduce the existing morning and evening peak, but create three new and sharper peaks: early morning, mid-day, and late night. As a result, the Industrial Curtailment program is not able to effectively address the altered peak day load curve, thereby reducing its overall effectiveness. This means that any additional potential is highly constrained by the load shape, rather than the program cost-effectiveness or market size.

IIC: DEMAND RESPONSE ACHIEVABLE POTENTIAL SAVINGS

The three DR achievable potential scenarios were assessed, each including the measures and programs that fit the scenario DR strategy, lowered peak demand, and were found to achieve a PACT result of greater than or equal to 1.0. **Figure 4-9** presents achievable potential through each scenario, but does not account for program ramp-up for new programs. Further details on program ramp up and costs can be found in Appendix F.

Figure 4-9. IIC Achievable Peak Savings Scenario Results Based on Program Start Year



SCENARIO 1: OPTIMISE EXISTING CURTAILMENT

Currently the NL Utilities have 125 MW enrolled under a large industrial curtailment program in the IIC system, which represents a little above 60% of the coincident peak load from this segment. The analysis assumed that further enrollment of industrial curtailment could be achieved and assessed the degree to which further enrollment would reduce the utility peak.

- **Expanding small and medium industrial customer participation in curtailment programs may offer a streamlined approach to achieve significant peak demand savings:** To further increase potential, enrollment can be expanded among the remaining industrial customers, including small and medium industrials. This approach alone could offer as much peak load savings as the multi-sector approaches assessed in the other scenarios. Under the Industrial Only scenario, around 70% of the industrial customer peak load would be curtailed. Other jurisdictions achieved an upper limit of large industrial around 80%.

- **Additional Potential can be achieved through a Dual-Fuel Program:** Dual-Fuel heating for residential and commercial customers who currently have central electric heating could offer an additional potential of up to 24 MW of peak demand reduction.

- **Further study may be warranted to determine the degree of enrollment possible among industrial customers:** The industrial segment technical potential was determined based on a high-level assumption that NL Utilities have already enrolled key large industrial curtailment and applying professional judgement to the portion of additional small and medium industrial curtailable load that could be achievable based on previous assessments performed in Atlantic Canada. NL Utilities may wish to further assess the costs and feasibility of achieving the levels of large industrial segment enrollment in DR programs, and perform a comparative analysis of the costs and reliability of these peak demand reductions vis-à-vis other high potential opportunities, such as residential domestic setpoint control or hot water direct load controls.

SCENARIO 2: RATE-BASED DR EXPANSION

Scenario 2 analysed the achievable potential when rates-based measures are added to the current program mix. This analysis focused on the optimized two-tier, 2:1 TOU rate program described earlier. From this analysis the following is observed:

- **The optimised two-tier 2:1 TOU Rates program applied to all residential and commercial customers offers limited peak reductions:** We assessed TOU savings assuming a high retention in an opt-out program, and a low peak to off-peak ratio (≈2:1). This results in less savings than is achievable under the Equipment Controls and Optimized Current Curtailment only scenarios, as the TOU impacts do not blend well with the current constraints on large industrial programs (notably, Corner Brook Pulp & Paper Ltd.).

- **The TOU rates program changes the utility curve such that it leads to reduced Industrial Curtailment program effectiveness, thereby leading to a net reduction in the overall achievable potential in Scenario 2:** TOU Rates programs applied in the residential and commercial sectors help to flatten the peak day load curve and displace the demand savings from the initial DR windows. This conflicts with the Industrial Curtailment contract constraints thereby reducing the large industrial segment savings potential. Further details and explanation of why this occurs is provided in Appendix F.

SCENARIO 3: EQUIPMENT CONTROL DR EXPANSION

In the third program scenario, the Equipment Control and Dual Fuels programs were added to the existing programs and the overall achievable potential was assessed, leading to the following observations:

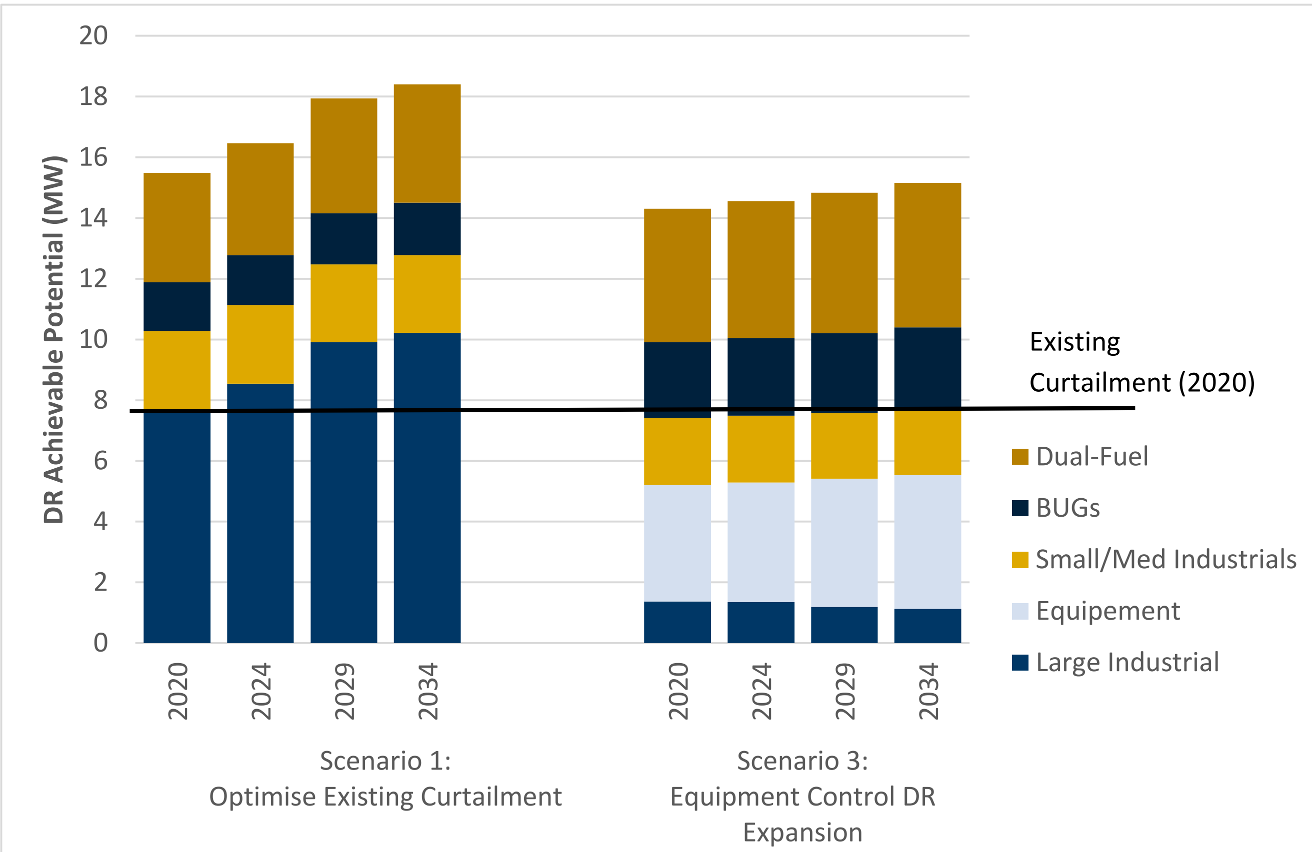
- **The prevalence of electric heating and water heaters allows residential setpoint control and domestic water heater controls may offer the only notable peak load reductions out of all Equipment Control options:** Up to 26 MW of Equipment Control achievable potential was assessed, primarily stemming from direct utility control of electric water heaters and space-heating for residential customers. Water heaters exhibit a high coincident demand with the utility peak (early mornings) and can typically be controlled remotely to reduce demand without disrupting customer comfort. Residential space heating exhibits a lower coincident factor, but the importance of the residential space heating load during peak event allows savings that are close to water heaters.

- **The Equipment Controls program changes the utility curve such that it leads to reduced Industrial Curtailment program effectiveness, thereby leading to a net reduction in the overall achievable potential in Scenario 3:** As with TOU, adding the Equipment Control program undermines the achievable potential from the Industrial Curtailment program, thereby offering a reduction in the overall achievable potential in the early years, and a slight increase by 2034. Given these findings, it is hard to see a justification for investing in Equipment Control program infrastructure, unless adjusting the Industrial Curtailment contracts proves to alter the DR potential of other measures. The Utilities will complete this analysis.

LAB: DEMAND RESPONSE ACHIEVABLE POTENTIAL SAVINGS

The three DR achievable potential scenarios were assessed, each including the measures and programs that fit the scenario DR strategy, lowered peak demand, and were found to achieve a PACT result of greater than or equal to 1.0. For the LAB system, TOU rate design increased the standard peak day load, and therefore it was not retained for further analysis. **Figure 4-10** presents achievable potential through each scenario, but does not account for program ramp-up for new programs. Further details on program ramp up and costs can be found in Appendix F.

Figure 4-10. LAB Achievable Peak Savings Scenario Results Based on Program Start Year



SCENARIO 1: OPTIMISE EXISTING CURTAILMENT

Currently LAB system has 30 MW enrolled under large industrial curtailment, which represents a little above 15% of the coincident peak load from this segment. The analysis assumed that further enrollment of industrial curtailment could be achieved, and then assessed the degree to which further enrollment could be applied against the utility peak.

- **Large industrial curtailment expansion in the LAB is dependent on IOC:** IOC operations are responsible for over 50% of the peak demand in Labrador. NL Utilities already have enrolled IOC in a large industrial curtailment program. As IOC is responsible for such a large share of the system demand, it brings challenges to system load management. Communication with IOC is key in order to be aware of modifications in energy consumption regime.

- **Extending the industrial curtailment program to include the small and medium industrials may offer a streamlined approach to achieve significant peak demand savings:** Similar to IIC, enrollment in curtailment programs can be expanded among the remaining industrial customers, including small and medium industrials. This approach alone could offer as much peak load savings as the multi-sector approaches assessed in the other scenarios. Under the Industrial Only scenario, around 5% of the industrial customer peak load would be curtailed.

- **Adding Dual-Fuel and BUGs Programs could offer further potential:** Adding Dual-Fuel and BUGs programs could offer a further 6 MW of achievable peak load reduction potential. This would ideally be carried out as an extension of the IIC programs, as 6 MW may not be sufficient to justify a program for LAB system customers alone.

SCENARIO 2: RATE-BASED DR EXPANSION

The optimized two-tier, 2:1 TOU Rates program design led to an increase in the annual peak for the LAB system, and therefore Scenario 2 program was not assessed: Based on these results it is concluded that there is little potential for TOU Rates to have a beneficial impact in the LAB system, even if Industrial Curtailment contracts can be adjusted. This scenario was therefore not assessed further.

SCENARIO 3: EQUIPMENT CONTROL DR EXPANSION

Finally, Scenario 3 included an Equipment Controls Program, along with Dual-Fuel and BUGs programs to assess the overall achievable potential from this mix. The follow results emerged:

- **The prevalence of electric heating and water heaters allows residential setpoint control and domestic water heater controls to be the most significant single peak demand reducing measure:** Around 80% of residential heating systems and water heaters in the LAB system are electric-powered. The potential from equipment control is limited by LAB load shape, but equipment control from IIC could be extended to LAB, offering 4 MW of achievable potential peak load reductions.

- **Adding the Equipment Controls Program undermines the current industrial curtailment potential, leading to an overall reduction in the achievable potential as compared to Scenario 1:** As for IIC, equipment program generally creates a negative impact on industrial curtailment, reducing its net peak load reduction impact from 8 MW to 1 MW in 2020. Since the IOC curtailment contract constraints have not yet been established, NL Hydro may want to request longer curtailment event durations than are currently applied in the IIC contracts, thereby minimizing the negative interactions with a possible Equipment Control program in the future.

DR POTENTIAL: KEY TAKE-AWAYS

Based on the results of assessing the DR potential from three program scenarios, there is an apparent 202 MW of demand response potential in the LAB and IIC systems, representing 9.2% of the annual peak load. Much of this potential is already being accessed through the existing Industrial and Commercial Programs and CVR (IIC only), but this study assessed that a further 48 MW may be possible through existing program expansion, and adding a Dual-Fuel heating program for residential and commercial customers with central electric heating.

Table 4-6. Existing Curtailment and Scenarios Comparison (2034)

System	Existing potential	Scenario 1:	Scenario 2:	Scenario 3:
IIC	144	183	154	185
LAB	10	19	19[39]	15
Total	**154**	**202**	**173**	**200**

While there is a limited pool of DR potential assessments conducted for winter-peaking utility DR programs, a handful of studies were identified to benchmark the DR potential assessment for Newfoundland and Labrador (**Table 4-7** below).

Table 4-7. Benchmarking Newfoundland and Labrador DR Potential to Other Jurisdictions

	Newfoundland and Labrador (IIC and LAB combined)	Michigan [40]	Northwest Power & Cons. Council[41]	Puget Sound Energy[42]
Potential as a portion of Peak Load	10.4% (Winter peak) (9.2% in existing curtailment)	4.4%-7.7% (Summer peak)	8.8% (Winter peak)	3.7% (Winter peak)
Avoided Costs	$430 / kW	$140 / kW	n/a	$290 / kW

[39] Using best scenario (Scenario 1: Optimise Existing Curtailment) since TOU is not improving peak demand savings for LAB system.

[40] State of Michigan Demand Response Potential Study, AEG (2017).

[41] Assessing Demand Response (DR) Program Potential for The Seventh Power Plan, Navigant (2014).

[42] Puget Sound Energy Demand Response Potential Assessment (2017)

Based on the findings in this report three key take-aways emerge:

- **Existing industrial curtailment contracts place Newfoundland and Labrador at the high end of achievable range when benchmarked against other jurisdictions:** The Industrial Curtailment program has significant enrolled capacity that appears to be well suited to reducing peak loads on the IIC system in particular. Further potential may exist to expand this program among more Small and Medium industrial customers as well. A dual-fuel heating program for residential and commercial customers could also add notably to the DR potential in both systems.

- **Newfoundland and Labrador's relatively flat peak-day load shape limits DR potential in residential and commercial buildings:** Utilities that experience peak demand resulting from electric resistance heating typically exhibit high inter-seasonal and day-to-day variation, but the load curve on the actual peak days tends to be relatively flat compared to summer peaking utility load curves. This limits the ability for measures that tend to shift loads to other times of the day, like TOU rates, water heating and HVAC controls, to reduce peak demand, as they can quickly create a new peak from the bounce-back demand experienced after the DR event. Our results indicate that this limits the potential from residential and commercial buildings to just 23 MW, which represents just 1.5% of the annual peak load. Moreover, an equipment control program could negatively impact the potential from industrial curtailment, thereby reducing or eliminating its net benefit to the system. Instead measures such as dual-fuel heating or activating BUGs, which have no rebound peak effects, may provide the best option to include commercial and residential customers in DR programs.

- **While TOU Rates and Equipment Control programs did not appear to offer additional DR potential, adjustments to the existing Industrial Curtailment programs, incorporating more aggressive EV adoption peak load impacts, or adding the Fuel Switching load curve impacts, all may alter conditions such that TOU Rates, CPP and/or Equipment Controls could become effective in the future:** Changes to the utility load curve or to the constraints applied in other programs have significantly impacted the interactions among programs. For example, if the NL Utilities are able to negotiate Industrial Curtailment contracts with longer DR event durations, it may be possible that TOU Rates, CPP and Equipment Program could offer additional potential as compared to the results presented herein. The Utilities will undertake a study to complete this analysis.

Overall, it appears that maintaining the utilities focus on industrial and commercial curtailment is the best option to optimize the DR achievable potential in NL.

Consideration of Curtailment Flexibility and Further Integration of EV Adoption and Fuel Switching Impact

Increased flexibility for the industrial curtailment contracts could increase the potential from other programs. Further analysis of this potential will be undertaken by the Utilities. It should also be noted that the results presented in study indicate that Fuel Switching and EV Adoption could significantly alter the utility load curve shapes, which may create an opening for the TOU Rates, CPP and Equipment Controls programs to add further peak load reduction potentials. As the needed information becomes available, the Utilities will conduct further assessments.

5. FUEL SWITCHING POTENTIAL

A fuel switching analysis was conducted to assess how many households and businesses can be expected to replace or supplement oil- and wood-fired space heating and domestic hot water (DHW) heating systems with electric heat pump systems under various levels of incentives. The analysis tests three scenarios – one without any incentives (Lower) and two with various levels of incentives (Mid, Upper). The latter two scenarios provide financial incentives to reduce the upfront costs associated with fuel switching (e.g. the incremental cost of buying a central air source heat pump instead of an oil furnace or the full cost of adding a ductless mini-split heat pump to an existing heat system). The incentive scenarios also reduce barrier levels in the model to simulate education and outreach efforts that make fuel switching less daunting to consumers. **Figure 5-1** describes each scenario.

Figure 5-1. Fuel Switching Scenarios Applied in this Study

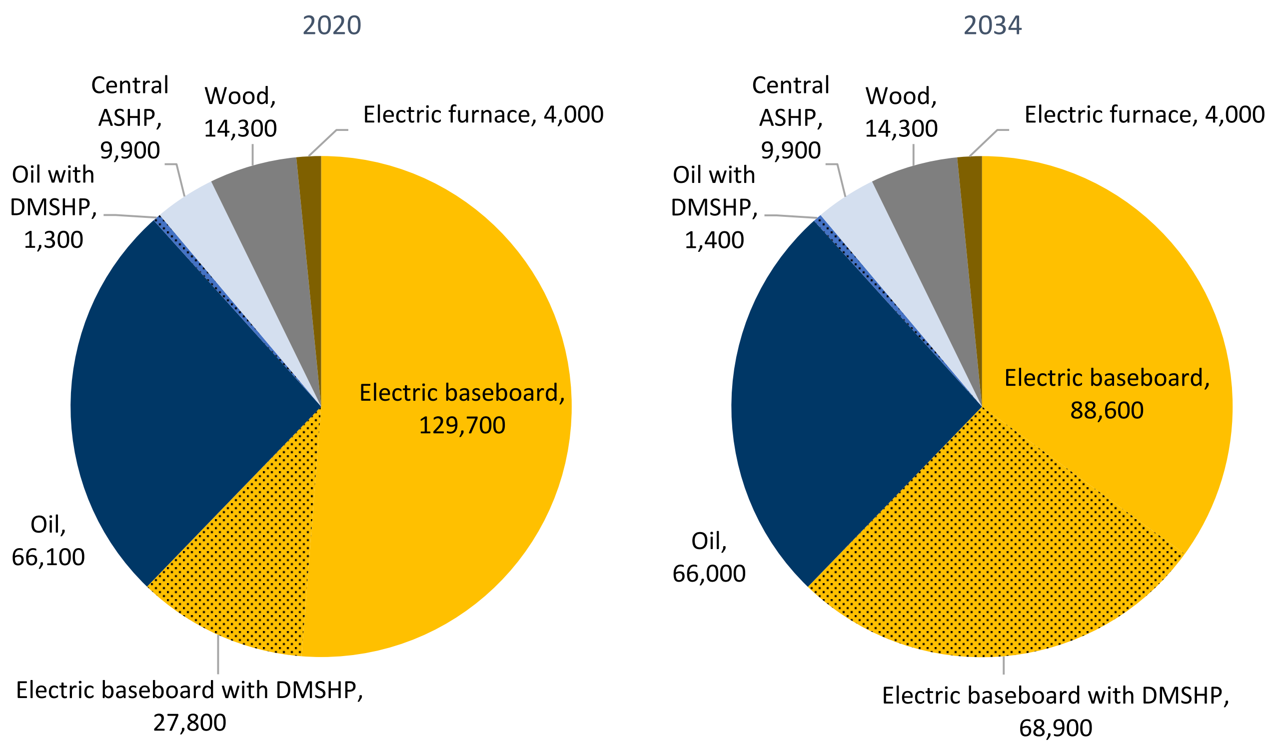
Lower	•**No Incentives** No incentives are offered. Fuel switching is what would be expected without any market intervention.
Mid	•**35% Incentive** An incentive to cover 35% of the incremental cost of the measure is applied, **plus a ½ step reduction in barrier levels**.
Upper	•**70% Incentive** An incentive to cover 70% of the incremental cost of the measure is applied, **plus a full step reduction in barrier levels.**

For each scenario, the analysis assumes Mid-rates and no carbon tax applied to fuel oil for heating. While the adoption of DMSHPs by electric baseboard households is characterized as part of the analysis, the measure **does not receive incentives under any scenario** since there is significant natural adoption of DMSHPs by these households already**.** Appendix C describes the fuel switching modelling methodology in detail. Details on the input and assumptions behind the analysis presented in this chapter can be found in Appendix E, and detailed results are included in Appendix F. The remainder of this chapter describes the results of the analysis.

LOWER SCENARIO – NO UTILITY INCENTIVES

Under the Lower scenario, where no incentives are offered to encourage oil and wood heated homes to switch to electric heat pumps, there is little to no expected fuel switching in both residential and commercial sectors. The only significant change is in residential households with existing electric baseboard heating. Of these homes, an additional 41,000 households (approximately 16% of all households) are expected to add DMSHPs to their baseboard heating systems between 2020 and 2034. In comparison, roughly 100 additional households with oil heating are projected to add DMSHPs, and no homes with wood heating adopt heat pumps. No households completely replace their heating systems with central air source heat pumps (ASHP). Additionally, almost no households and businesses with oil-fired domestic water heating would be expected to switch to heat pump water heaters. **Figure 5-2** shows the number of households with various heating systems at the beginning and end of the study period under the Lower scenario.

Figure 5-2. Residential heating systems under business-as-usual conditions (number of households)



The adoption of DMSHP by electric baseboard households leads to significant net energy and demand reductions as shown in **Figure 5-3** and **Figure 5-4**, respectively. By 2034 under the Mid rate scenario, electric sales will be reduced by nearly 140 GWh annually, and peak demand will be reduced by approximately 80 MW. Compared to forecasted electric sales and demand, these represent decreases in sales and demand of approximately 2.1% and 3.8%, respectively. There is a greater proportional impact on demand due to the larger contribution of residential heating load to system-wide peak demand relative to its contribution to system-wide electricity consumption (for assumptions regarding DMSHP peak demand impacts, see Appendix E). Higher electricity rates would likely drive even greater adoption of DMSHP by electric baseboard households leading to larger net energy and demand reductions, while lower rates will reduce adoption.

Figure 5-3. Net energy impact from Heat Pump adoption: Lower Scenario

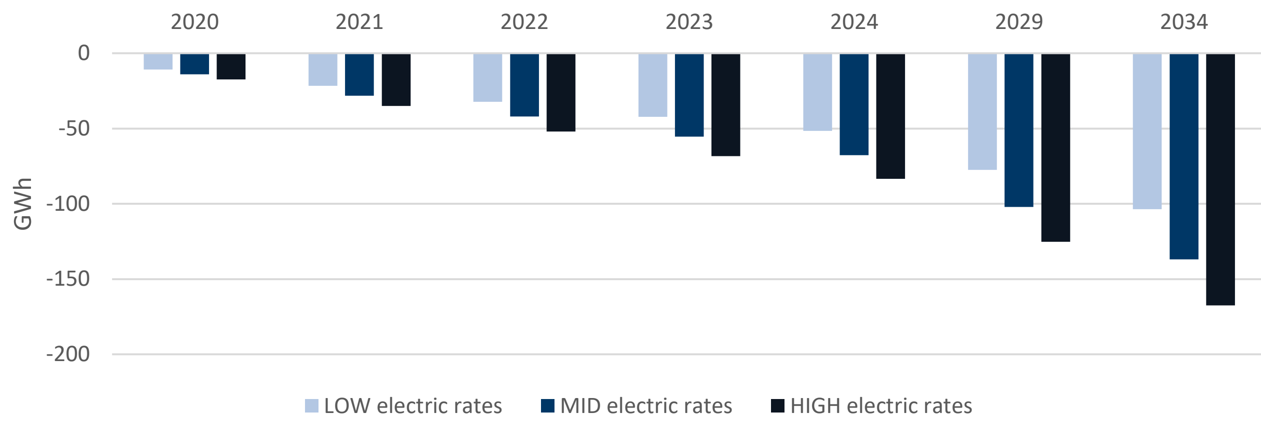
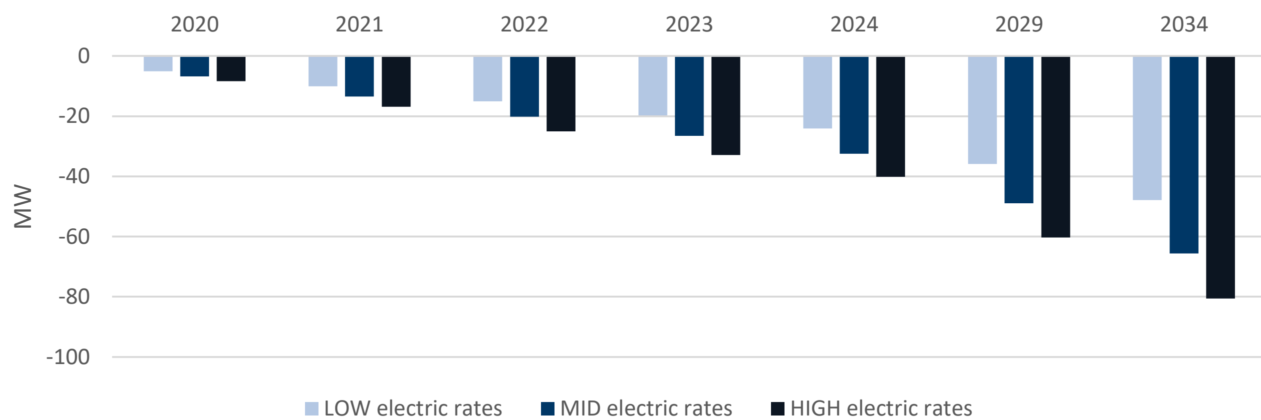


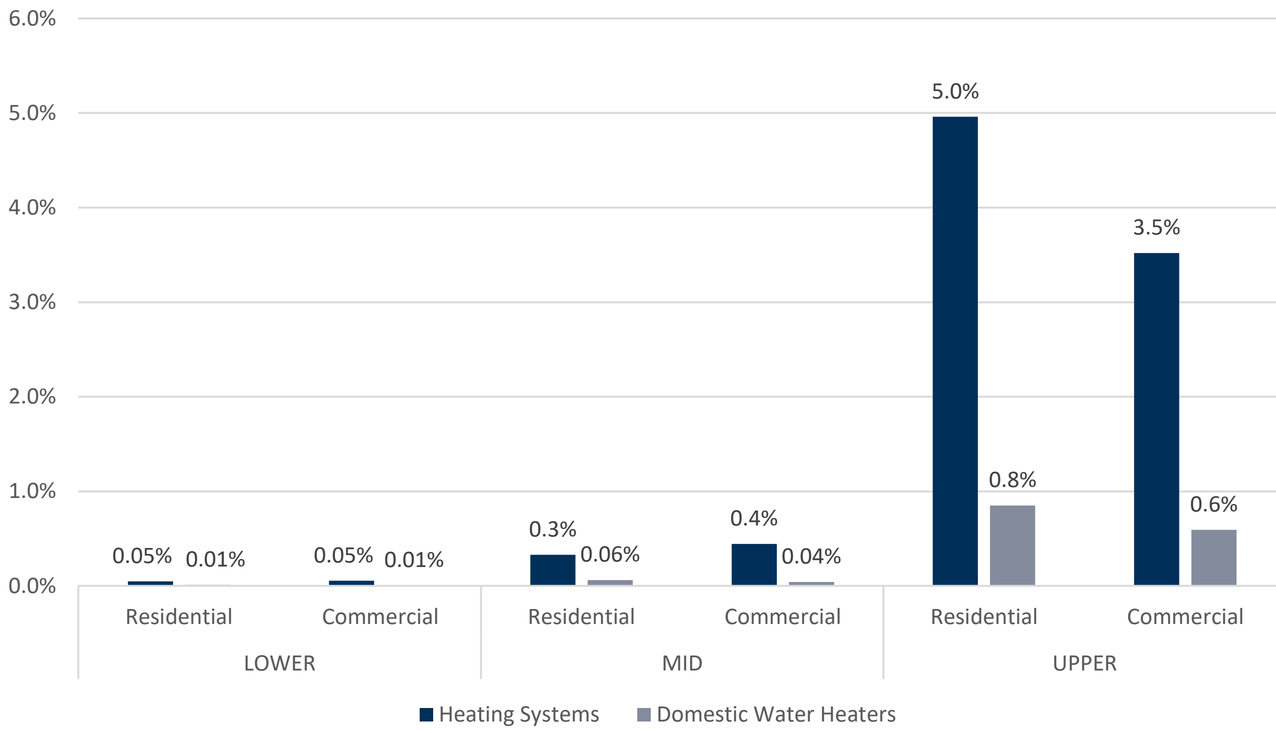
Figure 5-4. Net demand impact from Heat Pump adoption: Lower Scenario



INCENTIVIZING FUEL SWITCHING

Providing incentives for customers to adopt heat pumps for space heating and domestic water heating can help move the market if the incentives are large enough. Overall, the analysis only finds significant fuel switching in the Upper scenario. As shown in **Figure 5-5**, when customers are provided a 70% incentive (plus full-step barrier reduction), approximately 5% of all residential customers and 3.5% of all commercial floor space opt to replace their oil-fired heating system with a central ASHP or add a DMSHP to an existing oil-fired heating system. Since approximately 26.6% of homes and 22.3% of commercial floor space is heated with oil, this translates to roughly 19% of residential households and 16% of commercial floor space with oil heating opting for a heat pump heating system. Less than 1% of all residential and commercial customers replace oil-fired domestic water heaters with heat pump domestic water heaters in the Upper scenario, which translates to approximately 3% and 1% of residential and commercial customers with oil-fired domestic water heating making the switch, respectively.[43]

Figure 5-5. Percent of customers switching from combustible fuel systems to heat pump systems (2034)



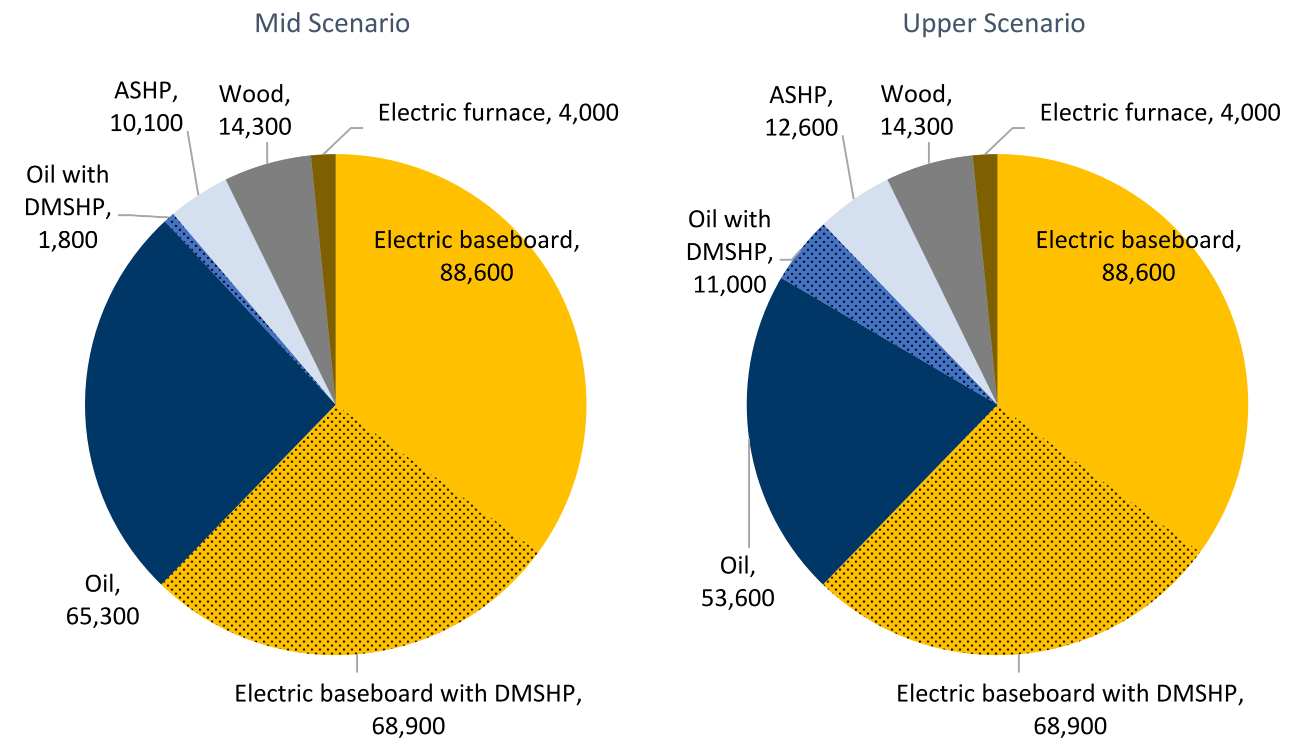
Note: For heating systems, residential adoption is expressed as a percentage of households, while commercial adoption is expressed as a percent of square footage.

[43] Note: Switching from electric resistance to heat pump domestic water heaters is characterized in the CDM portion of this study.

RESIDENTIAL SECTOR

In the residential sector, some households with oil-fired heating systems are likely to adopt heat pumps to replace their current heating system under both incentive scenarios. Households with wood-fired heating systems are not expected to switch to heat pumps primarily due to the low cost of wood fuel compared to electricity. **Figure 5-6** shows the projected breakdown in residential heating systems in 2034 under each scenario. In both cases, more customers are expected to be heated by air source heat pumps (ASHP) or DMSHPs. Under the Mid scenario, approximately 800 households (0.3% of all residential customers) with oil-fired heating adopt heat pumps between 2020 and 2034, while under the Upper scenario, approximately 12,500 oil-fired heating households (5% of all residential customers) adopt heat pumps.

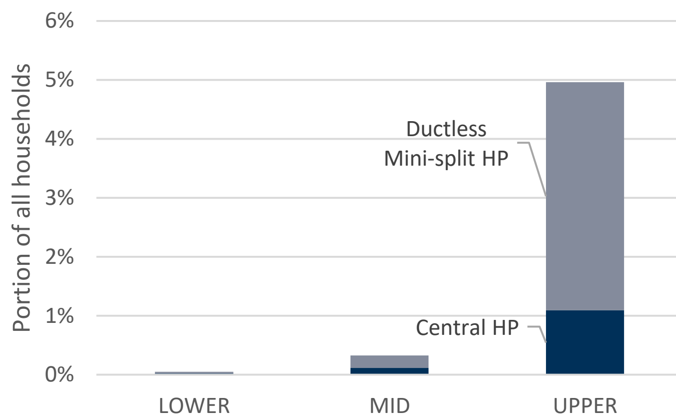
Figure 5-6. Residential heating systems in 2034 under incentive scenarios (number of households)



Note: Incentives are not provided to households with electric baseboard heating under any scenario.

Most households adopting heat pumps choose to add DMSHPs to their existing system over full replacement with a central heat pump (e.g. ASHP). **Figure 5-7** shows the breakdown between the adoption of central heat pumps and DMSHPs.

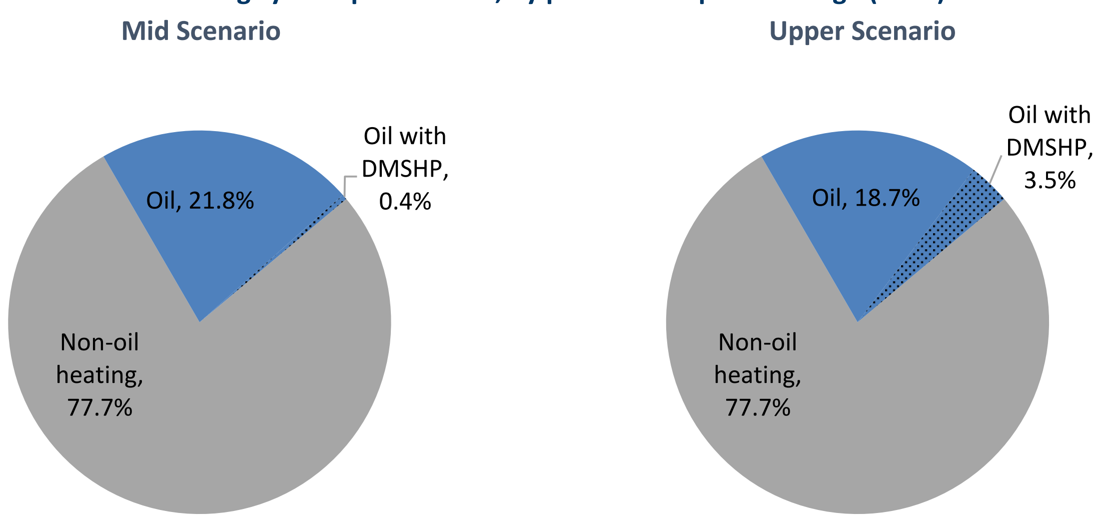
Figure 5-7. Adoption of heat pumps by oil-heated homes, by heat pump technology (2034)



COMMERCIAL SECTOR

In the commercial sector, some businesses will likely be willing to adopt DMSHPs to supplement existing oil-fired heating systems under all incentive scenarios. However, there is no projected adoption of central ASHPs to replace central oil-heating systems due to higher incremental costs for these systems. Under the Upper incentive scenario, 3.5% of commercial square footage is covered by DMSHPs by the end of the study period (see **Figure 5-8**).

Figure 5-8. Commercial heating system penetration, by percent of square footage (2034)

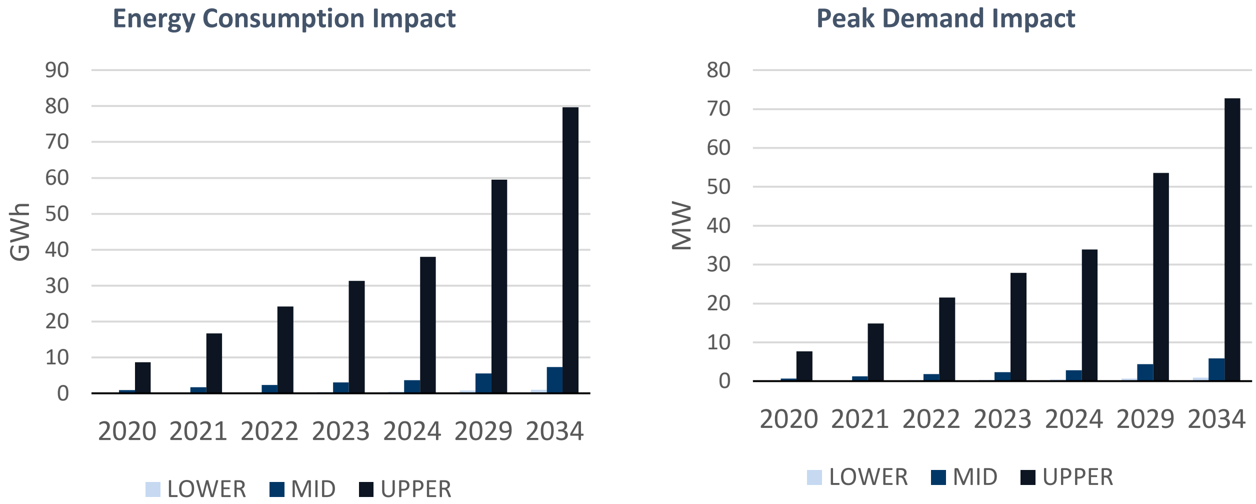


ENERGY AND DEMAND IMPACTS

The energy and demand impacts of customer fuel switching are displayed in **Figure 5-9**. Under the Upper incentive scenario, the adoption of heat pump technologies (for both spacing and domestic water heating) by oil-fired heating customers increases electricity consumption by approximately 80 GWh and peak demand by 70

MW by the end of the study period. There are minimal energy and demand impacts under the Mid incentive scenario due to low adoption.

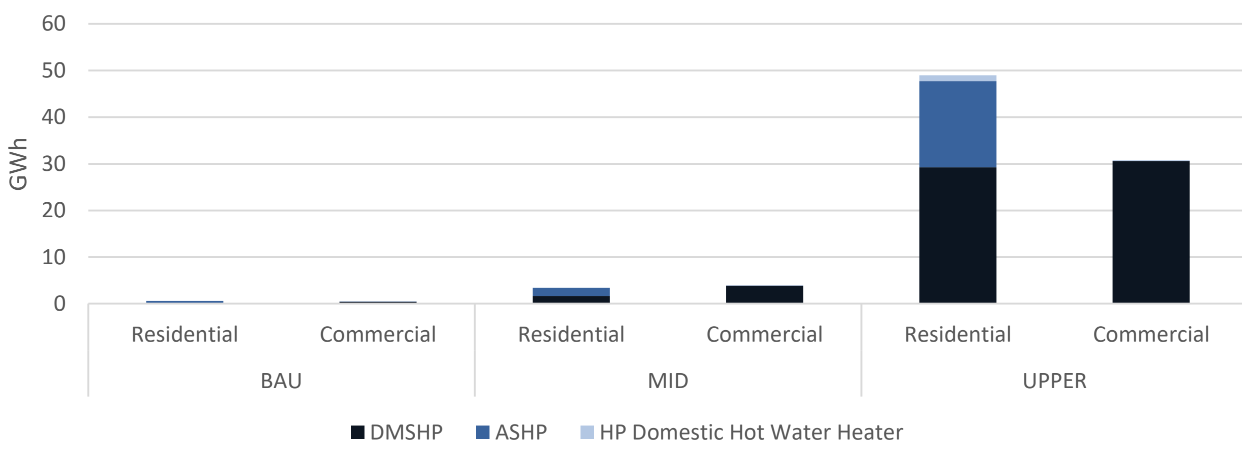
Figure 5-9. Fuel switching energy consumption and peak demand impacts



Note: Energy and demand impacts do not include energy savings from electric baseboard households adopting DMSHPs.

Under the Upper incentive scenario, the majority of energy impacts occur in the residential sector (approximately 61%), with significant energy impacts from the adoption of both DMSHP and ASHPs (see **Figure 5-10**). Approximately 39% of energy impacts occur in the commercial sector with almost all impacts from the adoption of DMSHP under the Upper incentive scenario.

Figure 5-10. Fuel switching energy impacts by sector and technology

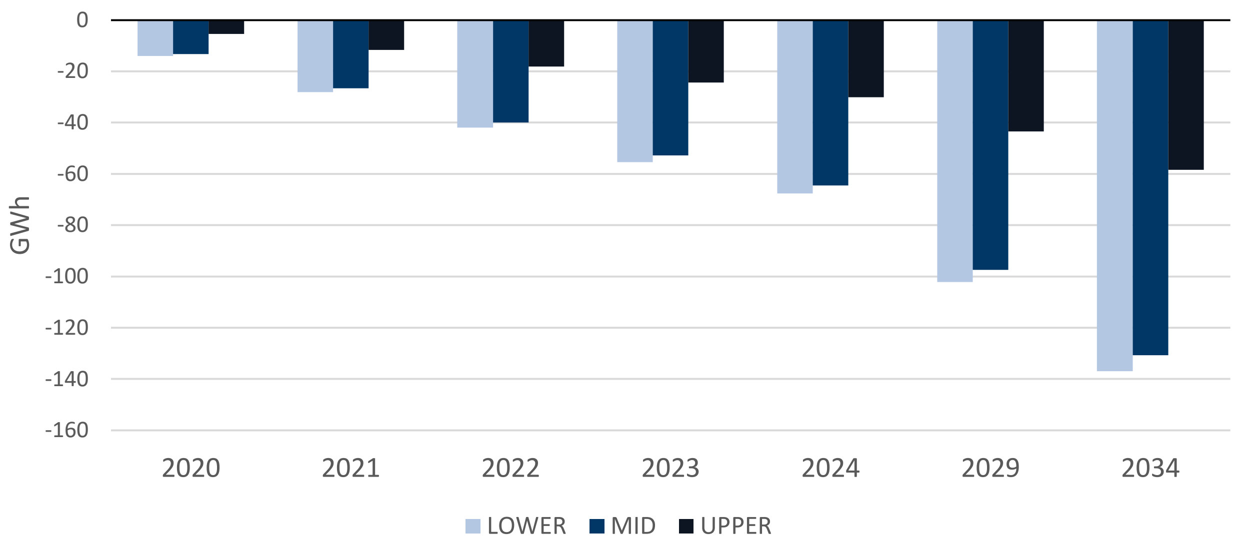


Note: Energy impacts do not include energy savings from electric baseboard households adopting DMSHPs.

NET ENERGY AND DEMAND IMPACTS

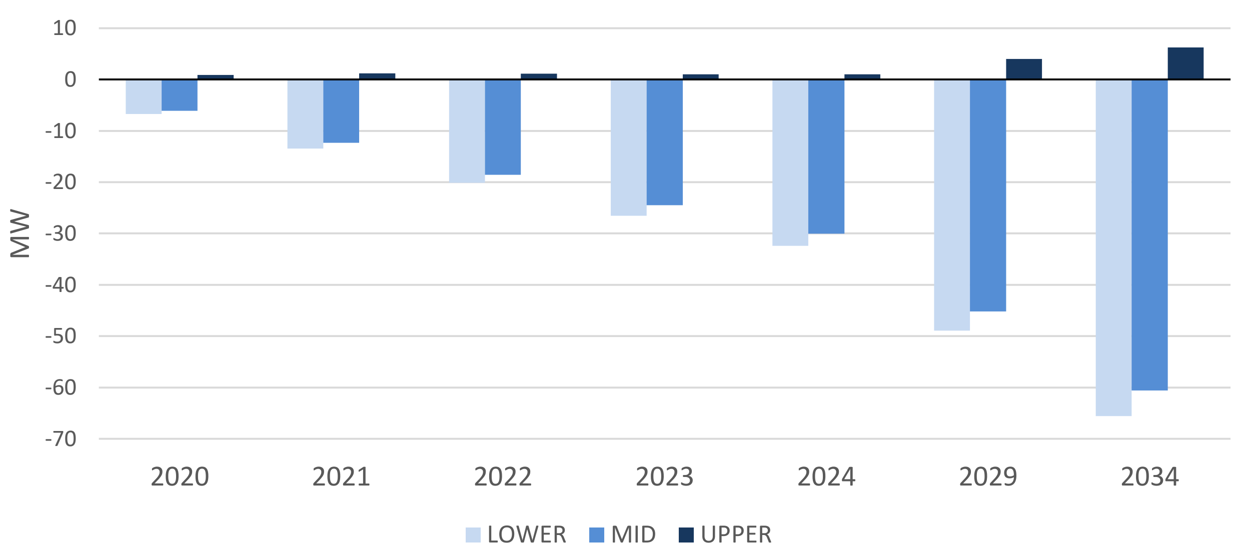
The increase in energy consumption due to oil-fired heating customers adopting heat pumps under the Upper incentive scenario offsets over half of the expected energy consumption reductions resulting from electric baseboard household adoption of DMSHPs as shown in **Figure 5-11**.

Figure 5-11. Fuel switching net energy impact (Mid-rates case)



For peak demand, however, the increase under the Upper incentive scenario more than offsets the expected demand reductions as shown in **Figure 5-12**. By 2034, there is a net increase in demand due to oil-fired customers adopting heat pumps – even when considering demand reductions from electric baseboard households adopting DMSHP. Fuel switching has a greater proportional impact on demand due to lower heat pump capacity and efficiency during peak hours, as is discussed in the call out box that follows **Figure 5-12**.

Figure 5-12. Fuel switching net demand impact



The Peak Demand Impacts of Heat Pump Adoption

The adoption of heat pumps by oil-heated customers has a bigger impact on net demand relative to net energy for two reasons:

1. DMSHPs have a muted demand reduction impact for electric baseboard households. When peak hours occur, generally during cold outdoor temperatures, DMSHPs will run at reduced efficiency and capacity. For electric baseboard homes, this means electric resistance heating will continue to pick up roughly half of the heating load normally covered by DMSHPs during these specific hours, thus reducing demand impacts.

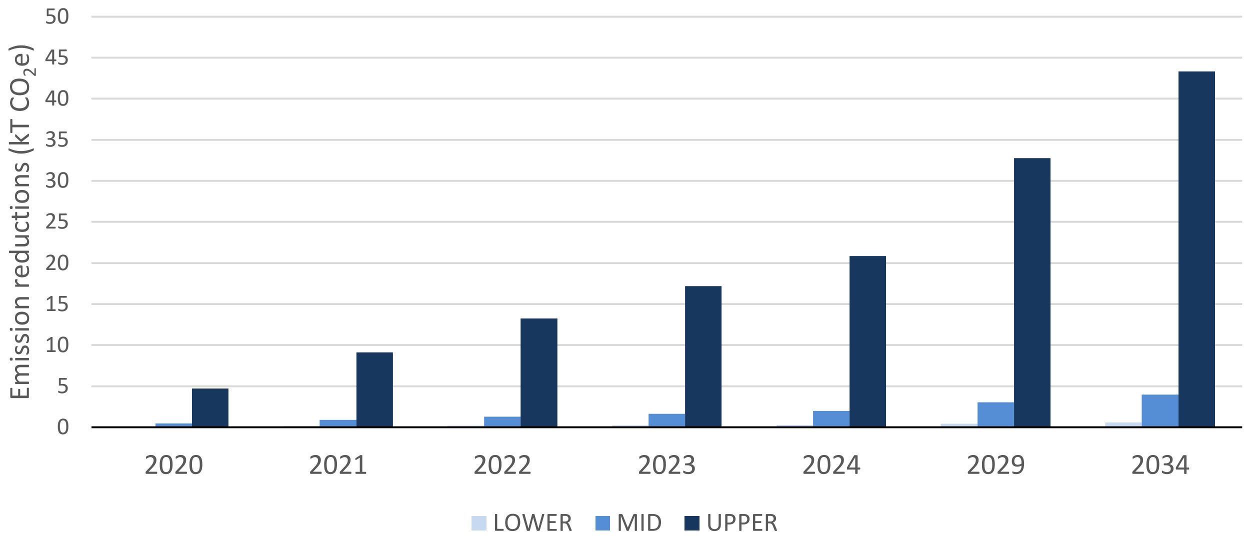
2. Replacing combustible fuel heating systems with a central heat pump (e.g. ASHP) can lead to significant demand increases. Like DMSHPs, these heat pumps will also operate at reduced efficiency and capacity during peak hours and will then rely on electric resistance back-up heating. This, in effect, replaces a heating system with no demand impacts (e.g. oil-fired furnace) with one with significant impacts (e.g. electric resistance heater) during peak hours. For the addition of DMSHP to oil-fired heating systems, there is no electric resistance backup, but these systems will still run during peak hours albeit at reduced capacity – thus contributing to demand impacts as well.

Further details on the Peak Demand assumptions applied in this analysis can be found in Appendix E.

GREENHOUSE GAS IMPACTS

Under the Upper incentive scenario, the reduction in oil consumption results in emission reductions of approximately 40 thousand tonnes of CO_2 equivalent (kT CO_2e) per year by 2034. There are relatively little emission reductions under the Mid incentive scenario due to low rates of fuel switching.

Figure 5-13. Fuel switching greenhouse gas emission reductions



INCENTIVE COSTS

Average annual incentive costs under the Mid incentive scenario are low due to low customer participation. Costs increase to just over $4.5 million per year on average under the Upper incentive scenario as the incentives make it more attractive for customers to fuel switch. In addition to relatively large incentives (i.e. 35% and 70%), the average incentive cost per customer is high because customers may adopt more than one DMSHP, effectively receiving multiple incentives per customer. Additionally, the average cost per customer does not double between scenarios (even though the incentive doubles) due to higher adoption of residential ASHPs, which are provided smaller incentives in the model due to smaller incremental costs. There are currently no utility programs to incentivize fuel switching, and potential programs have not been proposed. The costs in this section are based solely on the incentives paid to consumers within the model. They do not include any program administration costs or other ancillary costs.

Table 5-1. Fuel switching incentive costs

Scenario	Average annual incentive costs	Average cost per customer	Average cost per additional MWh in 2034
Mid	$177,000	$3,100	$360
Upper	$4,660,000	$4,500	$880

Note: Costs estimates include incentives for all measures and do not consider any program administration costs or other ancillary costs.

SENSITIVITY TO ELECTRICITY RATES AND CARBON PRICES

The fuel switching analysis results were tested for their sensitivity to both electricity rates and carbon pricing scenarios since both parameters can have significant impacts on the economics of fuel switching for consumers. Additionally, the utility incentive scenarios were tested for sensitivity to screening for the total resource cost (TRC) test.[44] **Table 5-2** describes each sensitivity scenario.

Table 5-2. Fuel switching sensitivity scenarios

Sensitivity	Description
Federal Government of Canada backstop carbon pricing plan (Fed. Backstop)	Oil rates include a carbon levy set at the Federal Government Backstop Carbon Pricing, which starts at $20 per tonne in 2019 and rising $10 per year to $50 per tonne in 2022.[45]
Social cost of carbon (SCC)	Oil rates include a carbon levy set at the upper bound of the social cost of carbon as estimated by Environment and Climate Change Canada.[46]
Unmitigated electricity rates (HIGH rates)	Retail electricity rates are assumed to be at the HIGH level.
Mitigated rates (LOW rates)	Retail electricity rates are assumed to be at the LOW level.

Figure 5-14 shows the difference in net energy impact, net demand impact, average annual incentives and GHG emission reductions for each sensitivity parameter except the TRC screening, which is described qualitatively. **Sensitivity scenarios are compared to a baseline scenario with Mid electric rates, no carbon levy on fuel oil, and under the Mid incentive level.**

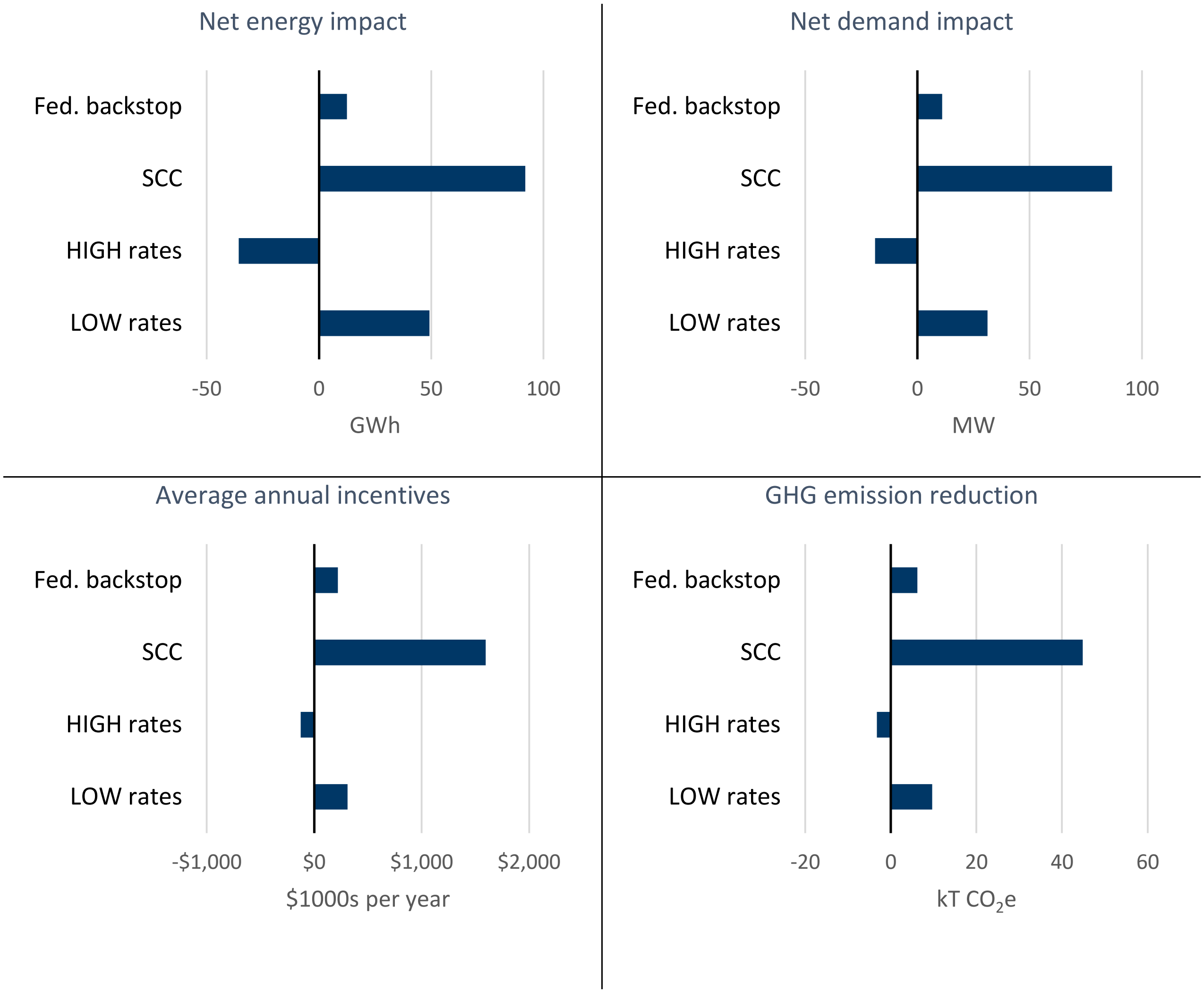
---

[44] The TRC screening excludes measures that do not pass the TRC test. The TRC test determines the net cost of each as a function of increased or decreased avoided costs of electricity and oil/wood consumption and electricity demand as well as the incremental costs of the measures regardless of who pays (e.g. the customer or the utility via incentives). This applied just to the modeled Incentive Scenarios, because the baseline scenario does not include for any utility intervention, but instead captures natural market adoption. Applying the TRC to control natural market adoption is not appropriate.

[45] Source: Government of Canada, Technical Paper on the Federal Carbon Pricing Backstop, https://www.canada.ca/content/dam/eccc/documents/pdf/20170518-2-en.pdf.

[46] Source: Government of Canada, Technical Update to Environment and Climate Change Canada's Social Cost of Greenhouse Gas Estimates, https://ec.gc.ca/cc/default.asp?lang=En&n=BE705779-1.

Figure 5-14. Fuel switching sensitivity analysis: Mid incentive scenario, 2034



Overall, the sensitivity analysis did not produce surprising results. When oil rates increase due to a carbon levy, there is a greater incentive to switch from oil to electric-based technologies. A larger carbon levy drives significantly greater fuel switching, but even a modest carbon levy increases fuel switching.

Conversely, when electricity rates are higher, there is less incentive to move away from oil-fired heating, but there is more incentive to add a DMSHP in electric baseboard households. This can be seen by the significant reduction in net energy and demand impacts under the High-rates case with a relatively smaller impact on average annual incentive payments.

When TRC screening is applied, only measures for domestic heat pump water heaters pass the cost-effectiveness screen to be included in the analysis. All measures for space heating fuel switching from oil are screened out. This is primarily due to the costs associated with increasing peak demand. For all measures, the value of displaced oil consumption is greater than the increase in costs for electricity consumption (set at the avoided cost rate). However, the increase in costs for electricity demand drives the TRC cost-benefit ratio below 0.8 for all measures except domestic heat pump water heaters.

FUEL SWITCHING: KEY TAKE-AWAYS

With a large incentive – 70% of incremental costs – along with enabling strategies that help reduce or remove customer barriers to adoption, approximately 5% of households and 3.5% commercial floor space adopts some form of heat pump heating system to displace oil-fired heating, while only marginal amounts of customers adopt heat pump domestic water heaters over oil-fired heating systems. At lower incentive levels, only a small number of customers with oil-fired heating systems make the switch, and with no incentives, almost no customers adopt heat pumps.

Based on the fuel switching analysis, the following key findings emerge:

- **The customer's economics *do not* favour fuel switching from oil or wood fired space heating.** For most customers, it does not make sense to adopt electric-based heating systems (space heating or domestic water heating) in favour of existing oil- and wood-fired heating systems – even when the electric systems are high efficiency heat pumps. Without significant incentives, consumers are unlikely to switch from combustible fuel-based systems to any sort of electric heating including heat pumps. This tendency will only be magnified if electric rates increase faster than assumed under the Mid-rates case.

- **The customer's economics *do* favour heat pumps in existing electric resistance heated households.** The market segment where heat pump systems do show the most economic benefits is households with electric baseboard heating. The analysis mirrors recent market data showing significant adoption of DMSHPs among households with electric baseboard heating, which leads to energy and demand reductions. If electricity rates increase, the economics will only improve for these customers leading to additional adoption and additional reductions in electricity sales.

- **Incentivizing the addition of DMSHP to existing oil-fired heating systems offers the most opportunity to increase electricity sales for the utilities.** Most customers adopted DMSHPs to displace heating from existing oil-fired heating systems, if they adopted anything at all. This choice avoids the costs associated with fully removing the legacy heating systems (e.g. oil tank removal). However, it should be noted that DMSHP measures did not pass TRC cost-effectiveness screening – mostly due to modeled increases in peak demand. Prior to any considerations to encourage fuel-switching to heat pumps, the peak demand impacts of heat pumps in Newfoundland and Labrador should be verified as this study used several non-jurisdictional specific assumptions to determine peak demand.

6. ELECTRIC VEHICLE ADOPTION

As the electric vehicle (EV) market continues to grow and evolve, utilities, governments, and private sector actors are beginning to take note and plan for increasing EV market shares. From a utility perspective, the electrical loads associated with EV adoption bring both opportunities and challenges; making them a critical element in future resource and program planning.

This section presents the results of projected EV uptake in Newfoundland and Labrador and corresponding impacts to the utilities.

APPROACH

This study leverages Dunsky's Electric Vehicle Adoption (EVA) model to forecast the adoption of Electric Vehicles (EVs) within Newfoundland and Labrador under several scenarios, assess the corresponding impacts of EV deployment on the Newfoundland and Labrador systems and identify strategies for interventions using the following approach:

- **Market Characterization:** Break down the market into vehicle segments and develop representative vehicle archetypes.
- **Model Calibration:** Benchmark Dunsky's EVA model to historical adoption in NL in order to calibrate key model parameters to local market conditions.
- **Scenario Analysis:** Use the calibrated model to assess the impacts of market and technology sensitivities, as well as key levers and interventions.
- **Utility Impacts:** Assess the energy consumption, load and financial impacts associated with the forecasted EV deployment.

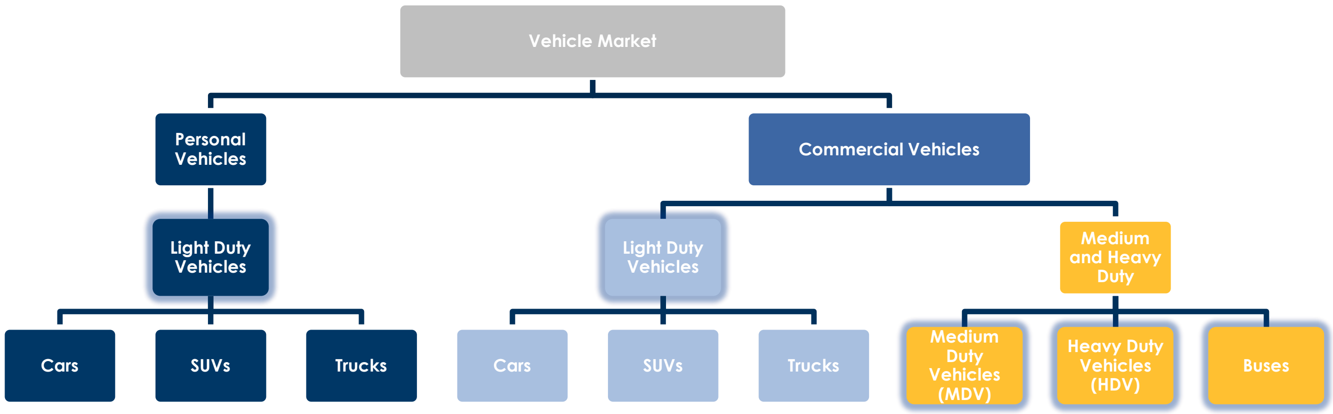
The study uses Newfoundland and Labrador specific inputs and assumptions to assess the potential for EVs in the province and assess corresponding opportunities and challenges. A more detailed description of the modeling approach, as well as key inputs and assumptions, are presented in Appendix D of the report.

MARKET AND VEHICLE CHARACTERIZATION

Due to differences in utilization and customer decision-making thresholds, the vehicle market in Newfoundland and Labrador was divided into personal and commercial vehicles. Additionally, the market was further segmented into vehicle classes that capture key differences between vehicle types, availability of EV models and utilization. As shown in **Figure 6- 1** below, the study captures nine distinct vehicle segments, however results are presented at the following levels:

- **Personal Light-Duty Vehicle (LDV)** including passenger cars, crossovers/SUVs and pickup-trucks.
- **Commercial Light-Duty Vehicles (LDV)** such as taxis, corporate and government fleet vehicles.
- **Medium-Duty Vehicles (MDV)** such as delivery vans, box trucks, utility bucket trucks.
- **Heavy-Duty Vehicles (HDV)** such as long-haul and short-haul semi tractors, garbage trucks, dump trucks.
- **Buses** including transit buses, school buses, coach buses.

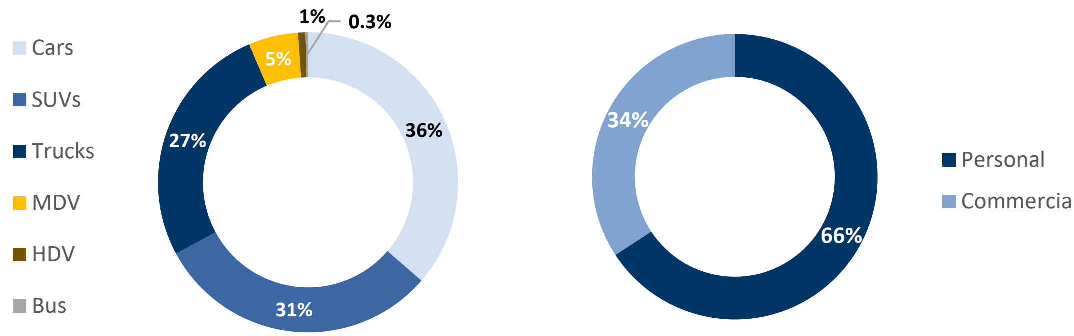
Figure 6- 1. Newfoundland and Labrador Vehicle Segmentation



For each of the modeled segments, a vehicle archetype capturing representative characteristics (e.g. annual distance traveled, fuel efficiency, battery size, powertrain output, etc.) of the average vehicle in that segment was developed. Key inputs and assumptions are presented in Appendix D. The medium-duty vehicles, heavy-duty vehicles and buses categories are a generalization of vehicles within this space to simplify the analysis. While vehicle characteristics of vehicles within each segment may vary significantly within depending on vehicle size, utilization and application, a representative average vehicle for each category was developed for the purpose of assessing the uptake within the category. Furthermore, medium- and heavy-duty categories are not always consistently defined within vehicle classification systems (i.e. some systems define medium-duty as classes 3 to 6, while other use classes 3 to 7) and certain vehicles straddle both the medium- and heavy-duty classifications. For example, refuse trucks can commonly range between Class 6 and Class 8. Likewise, short-haul freight semi-tractors can include both Class 7 and Class 8 trucks.

Based on publicly available data, annual vehicle sales in Newfoundland and Labrador were estimated at approximately 37,000 vehicles. As of 2019, approximately 410,000 on-road vehicles were registered in the province. 94% of vehicles in the province are estimated to be LDVs (i.e. cars, SUVs, trucks, etc.), with the remaining 6% being primarily MDVs as well as HDVs and buses. Additionally, 66% of vehicles are estimated to be primarily for personal use, with the remaining being commercial (i.e. non-personal use including corporates, governments, utilities, etc.).

Figure 6- 2. Distribution of Vehicle Sales in Newfoundland and Labrador



SCENARIO ANALYSIS

In this section, key results from the scenario analysis are presented with a focus on:

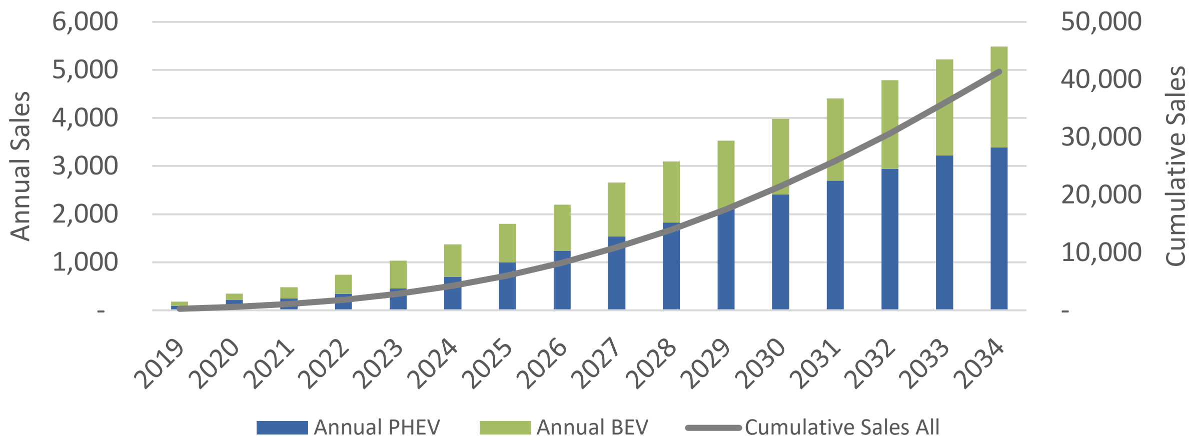
- **Baseline (business-as-usual):** A theoretical baseline which forecasts EV adoption under no further action beyond currently planned deployment (i.e. no new installed charging infrastructure, no incentives, etc.).[47] This baseline is primarily used to get insights into natural uptake of EVs in the province as well as to serve as a benchmark for assessing the impact of sensitivities and levers.
- **Sensitivities:** Assess the sensitivity of projections to factors linked to general competitiveness of the global EV market (lithium-ion battery costs, vehicle availability and technology advancements) and local market conditions (electricity rates, fuel rates and vehicle sales).
- **Levers:** Interventions that the utility, government, or other actors can make to accelerate the deployment of electric vehicles, namely public charging deployment (including DC Fast Chargers (DCFC) and Level 2 (L2)), home charging programs, and incentive programs.

BASELINE

As a first step, the adoption of EVs in Newfoundland and Labrador was forecasted under the assumption of no further program activity (i.e., – current levels of charging infrastructure, no incentives, etc.) in order to develop a theoretical baseline, presented in **Figure 6- 3, Figure 6- 4** and **Figure 6- 5**.

[47] Assuming existing committed actions by the utilities and government (estimated to be the installation of 14 DCFC and 30 Level 2 Ports in 2019/20)

Figure 6- 3. Baseline Annual and Cumulative Sales of Electric Vehicles in Newfoundland and Labrador, All Vehicle Classes



Under baseline conditions, the uptake of EVs is limited in the province. Approximately 41,400 EVs are expected to be on the road by 2034, representing between 10-29% of annual sales (varying by vehicle class), as seen in **Figure 6- 4**. In early years, BEVs have a higher purchase cost to their internal combustion engine (ICE) equivalent across all segments, ranging from 35% higher for Car BEV segment to 240% for the HDV BEV segment.[48] Additionally, the cost of a home/depot charger and installation further increases the incremental cost of an EV over an ICE. The high incremental cost of EVs over ICE equivalents results in limited market adoption across all vehicle class in early years, with EV adoption mostly composed of early adopter demographics whose decision to adopt is largely driven by non-financial considerations. With declining battery costs, the economic barrier facing EV adoption declines steadily, however the market remains significantly constrained by the limited availability of public charging infrastructure.

Throughout the study period, the market is dominated by plug-in hybrids electric vehicles (PHEVs) (62% by 2034). This trend can be attributed to range anxiety of EV purchasers coupled with low levels of public charging infrastructure in the province. PHEVs have the ability to use either an electric or internal combustion powertrain, typically providing sufficient electric mode range for daily driving distances while eliminating the range anxiety concerns associated with pure electric vehicles and increasing their popularity in jurisdictions with a limited public charging network.

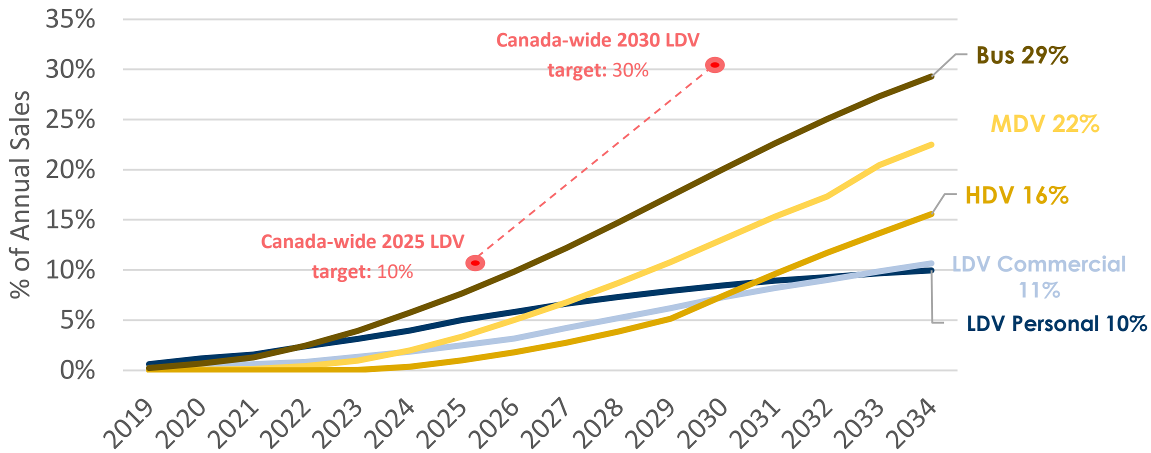
While the number of EVs on the road give a sense of the magnitude of adoption locally, EV projections and targets are often indicated in percentage of new annual vehicle sales. This metric serves as a normalized benchmark point for comparing adoption under different scenarios as well as across jurisdictions. The federal government has set Canada-wide targets for light-duty vehicles of 10% of electric new vehicle sales by 2025, 30% by 2030, and 100% by 2040. Similarly, global projections for the electrification of LDV are 30% of sales by 2030.[49] Under baseline conditions, uptake in Newfoundland and Labrador is forecasted to be much lower than

[48] Estimated vehicle purchase costs for ICE, PHEV and BEV models for each vehicle segment is presented in Appendix E.

[49] Bloomberg New Energy Finance. (2019). Electric Vehicle Outlook 2019. Available online: https://about.bnef.com/electric-vehicle-outlook/#toc-viewreport

these national and global targets, primarily due to charging infrastructure barriers, with only 10% of personal LDV sales and 11% of commercial LDV sales estimated to be EV by 2034.

Figure 6- 4. Baseline Percent of Electric New Vehicle Sales by Vehicle Class



Despite an early lead of personal light-duty vehicles, commercial vehicle segments reach a higher market share by the end of the study. Given lower anticipated dependence of commercial light-duty vehicles on public infrastructure, incremental upfront purchase cost and model availability become the primary barriers to uptake in these segments. As these factors improve over the course of the study period, uptake increases in response. In early years, medium- and heavy-duty vehicle uptake lags due to low model availability and high incremental costs of BEV models compared to their ICE equivalent, mirroring global forecasts.[50] However, over time, declining battery costs and increasing fuel costs improve total cost of ownership (TCO) and the business case for electric MDVs, particularly for urban delivery trucks and other return-to-base MDV fleets where battery size is not a constraining factor. By 2034, 22% of new MDV sales in Newfoundland and Labrador are projected to be EVs, on par with global projections of 20% by 2035. Adoption of electric HDV is likely to lag that of MDVs by a number of years, with nearly-zero uptake forecasted until 2025. Early adopters of EVs in the HDV segment are likely to be short-haul trucks and other vehicles that do not have significant range requirements.

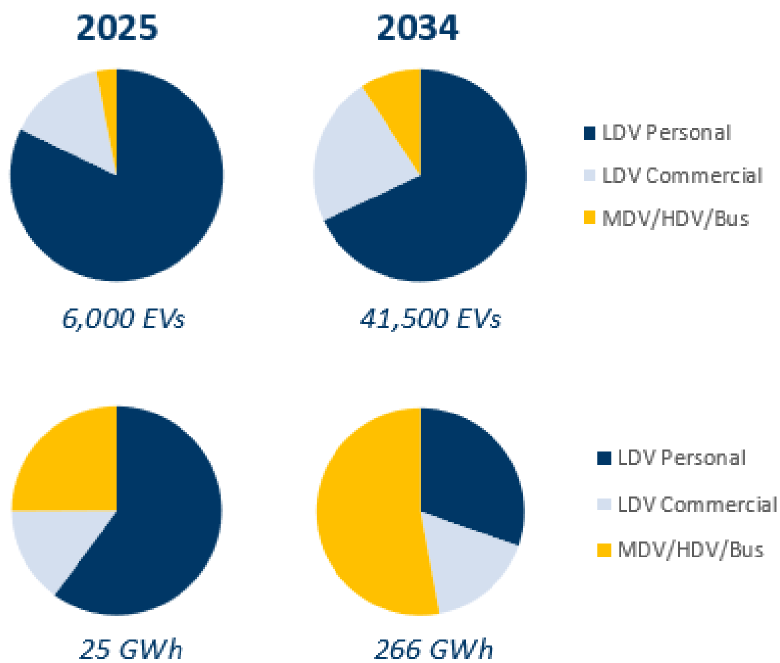
Most notably, natural uptake of electric buses significantly exceeds that of all other vehicle classes reaching 29% of sales by 2034. This is primarily due to high vehicle model availability and high utilization of some bus types, primarily transit, which improves the business case from a total cost of ownership perspective. A high portion of Newfoundland's buses are school buses, which typically have lower utilization and therefore lower potential for fuel savings than transit and other high-utilization bus fleets, resulting in lower uptake of buses overall than seen in global projections.

Despite light-duty personal vehicles representing the majority of EVs on the road at all points in the study period, as shown in **Figure 6- 5**, the majority of load impacts come from the medium-duty, heavy-duty, and bus vehicle classes given the higher utilization and size of these vehicle types and corresponding energy use. By 2034, EVs

[50] Ibid

are estimated to add 266 GWh of energy consumption to the utility's load; corresponding to roughly 5% of projected energy sales by 2034.

Figure 6- 5. Baseline Electric Vehicles and Electric Load by Vehicle Class



A diversified charging load profile was developed for each vehicle segment, leveraging data sets from a range of government and utility-led pilot programs. While the maximum rated power consumption of a single vehicle is important for considering the electrical load on a given home or even the impact on local distribution infrastructure due to clustering of EV adoption, system-wide impacts are best assessed using a diversified charging load profile which accounts for typical charging patterns across a larger population of EVs. For example, while a single LDV EV may be charged at a mix of Level 2 chargers (7 kW) and DCFC (50 kW+), considering the diversity in vehicle utilization and charging patterns, the system-wide peak load impact of the total LDV EV population is estimated at 1.5 kW per EV.[51] Using these diversified charging loads for each vehicle segment, a combined load profile for EV charging in Newfoundland and Labrador was developed, shown in **Figure 6- 6**.

Figure 6- 7 shows the energy impacts and peak load impacts of baseline levels of adoption throughout the study period. By 2034, the forecasted EV adoption would result in an additional 266 GWh of energy consumption (3% increase of 2034 energy consumption). Assuming no load management (i.e. no controlled charging, peak reduction programs or other interventions to shift EV charging), the high coincidence between the charging load

[51] Developed diversified charging load profiles are shown in Appendix D.

and the projected 2034 utility load curve results in an increase in peak load by 106 MW (5% increase of peak load in 2034).[52]

Figure 6- 6. 2034 Load Profile with and without Electric Vehicles, Assuming Unmanaged Charging

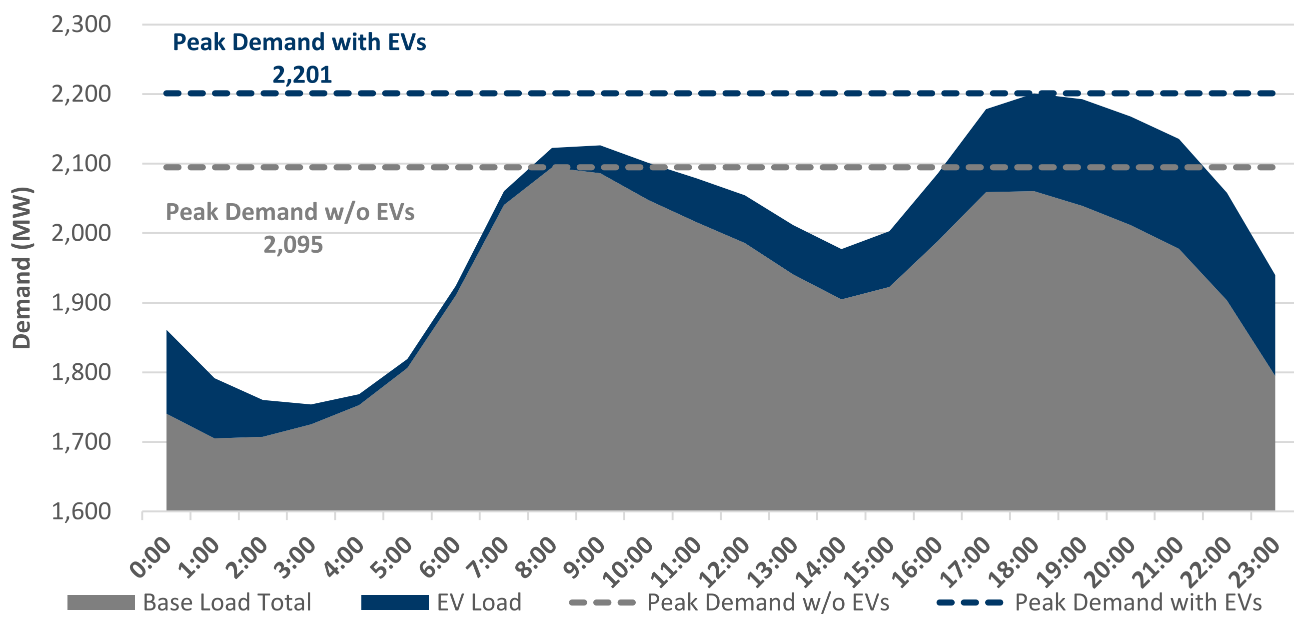
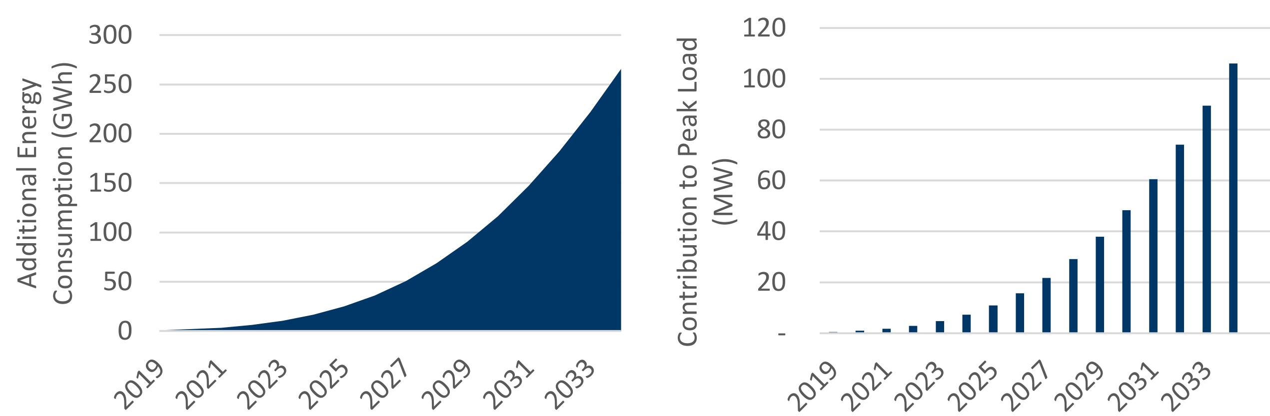


Figure 6- 7. Baseline Energy and Peak Load Impacts from Electric Vehicle Adoption



[52] Does not account for changes in load projections as resulting from Efficiency, DR or Fuel Switching potentials assessed elsewhere in this study.

SENSITIVITIES

Market realities often differ from projections due to changes in key market factors. Given uncertainties in both global factors (vehicle availability, battery costs) and local factors (number of vehicles sold, fuel prices, electricity rates) impacting EV adoption, low and high levels were developed for those key factors[53] and assessed for their impact on the energy consumption from EVs.[54] The results of the sensitivity analysis are shown in **Figure 6- 8**, **Figure 6- 9**, and **Figure 6- 10**, highlighting the impact of each factor on energy consumption in the short and long terms, with dark blue bars indicating an increase in the factor, and light blue indicating a decrease.

A number of key trends can be observed from the results:

- **Future vehicles sales will have a significant impact on the number of EVs on the road and load growth**. Although vehicle sales have traditionally been growing year-over-year, trends of declining vehicle sales are a disruption to the global mobility sector particularly with the advent of shared and autonomous vehicles. Additionally, vehicles sales are often tied to local characteristics such as population growth and economic development.
- **Vehicle availability is critical for EV adoption in the short-term across all vehicle segments:** Consumers are accustomed to having many options with respect to models, colours, and features when purchasing a new vehicle, and the limited variety of EV models currently being manufactured, and those available at dealerships even more so, constrain adoption of EVs. Additionally, EV models of medium and heavy-duty vehicles remain in early stage development, with only a handful of models available on the market today. An increase in the pace at which EV models become widely available has potential to increase market adoption across all segments. Similarly, a lag in availability will constrain the market in both the short and long terms.
- **Electricity rates and fuel costs have limited impact on the uptake of EVs in the personal segment**. Research indicates that consumers in the personal LDV segment are more likely to consider the upfront cost rather than TCO of EVs when making a purchase decision. The sensitivity of uptake in this segment to battery costs, which are tied directly to upfront costs, remains constant throughout the study period.
- **Commercial segments are sensitive to economic factors compared to the personal vehicle segment.** Changes to projected battery costs have a higher impact in the commercial segment, particularly medium and heavy-duty vehicles, due to the large battery sizes in the vehicles. Additionally, commercial operators are more likely to use more sophisticated financial assessments when making a purchase and consider TCO of vehicles rather than just the upfront costs. Particularly for medium and heavy-duty vehicles, which have very high utilization, changes in electricity rates or fuel prices have a substantial impact on the business case for EV adoption.

---

[53] Assumptions used for low, medium and high level of each factor are presented in Appendix E.

[54] The results show impacts on energy consumption from EVs (GWh) rather than impacts on adoption (number of cars), as energy sales is a more relevant metric for the utilities. Additionally, using energy sales as a proxy for assessing the impact on adoption of EVs captures the impact of factors on increasing the total number of EVs sales as well as in increasing the market share of BEVs relative to PHEVs. The cumulative EV sales data is provided in Appendix F.

Figure 6- 8. Sensitivity of Personal Light-Duty Vehicle Adoption to Key Market Factors

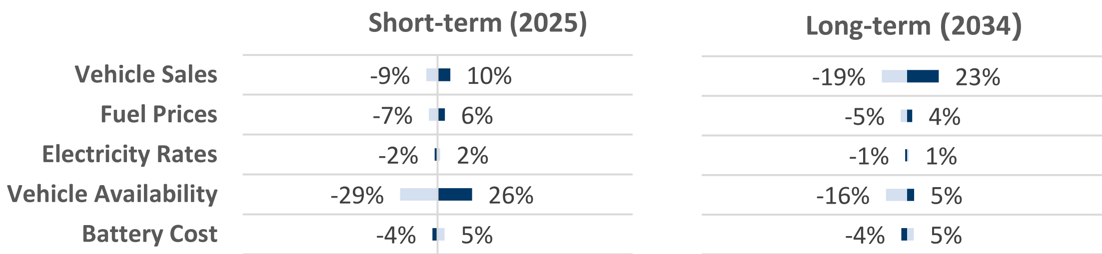


Figure 6- 9. Sensitivity of Commercial Light-Duty Vehicle Adoption to Key Market Factors

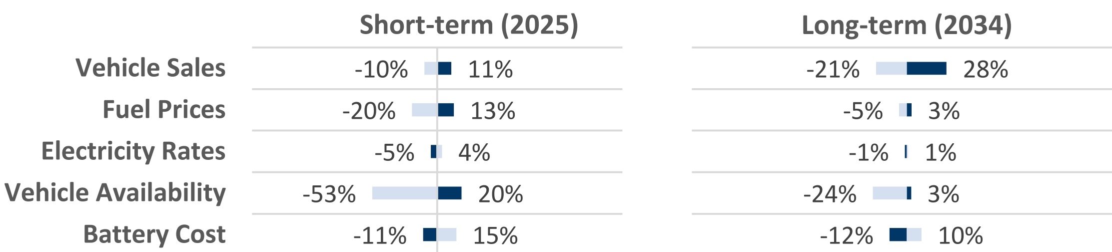
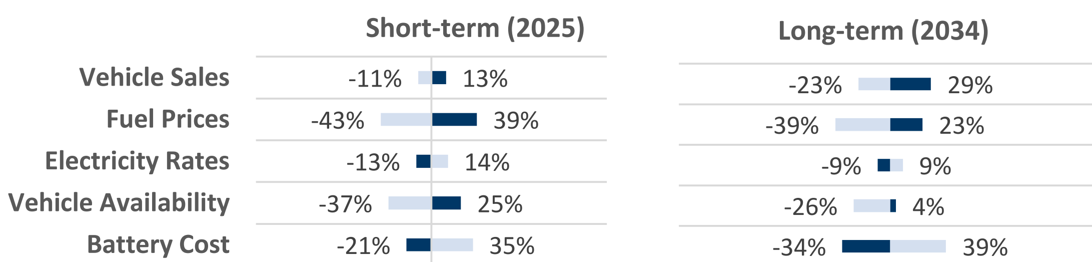


Figure 6- 10. Sensitivity of Medium-Duty, Heavy-Duty, and Bus Vehicle Adoption to Key Market Factors



Market dynamics are often linked, and several factors can change simultaneously. Therefore, in addition to investigating the impact of each factor in isolation, the analysis included an assessment of adoption and energy impacts under a "best-case" and "worst-case" scenario. Results show that energy load impacts of EVs under a low baseline and high baseline scenario range from 107 GWh to 448 GWh respectively, relative to 266 GWh under the assumed baseline.

MARKET LEVERS

Support and interventions from utilities, and governments and other market actors can have a significant impact on the growth of the EV market. In this section, three key levers commonly used to accelerate EV adoption are assessed for their impact to accelerate EV adoption in Newfoundland and Labrador.[55] For each factor, low and high investment scenarios were developed which correspond to investments of approximately $5M and $20M respectively over a 10-year period, as shown in the table below. To properly assess and attribute the impacts on adoption to a specific lever, **the levers are assessed in isolation** (i.e. the entire investment amount is assumed to be allocated to one lever only).

The modeled scenarios are not necessarily proposed investments by the utilities, but rather are designed to show the impacts of different levers on the market and determine what an appropriate investment strategy could be. The scenarios also do not represent all possible intervention options, however ones that are most relevant and likely to have an impact on market adoption by addressing key barriers to adoption. For example, a number of utilities offer incentive programs for the installation of home charging stations, however these strategies are usually not effective at driving additional EV adoption and mostly benefit existing EV adopters and increase free ridership. That said, incentives for home chargers can be used to cover the incremental cost of smart chargers for EV adopters to enable networking and load management functionalities.

Federal Incentives

The 2019 Federal Budget included $300 million in funding to be allocated over three years towards electric vehicle purchase incentives. At the time of writing, the incentive is in place across the country and available as a direct purchase incentive of up to $5,000 for eligible vehicle models. Due to uncertainty around future availability of the incentive, the federal EV incentives are not included in the baseline scenario. The Low Incentive Investment Scenario was developed to resemble the federal rebate levels (i.e. Modeled Incentives – Low can be interpreted as impact of federal incentives). The modeled Incentives – High scenario can be interpreted as the federal incentive in addition to an incentive top-up by the utilities or government.

[55] In addition to the levers indicated in the table below, Dunsky assessed the impacts of investments in a program to retrofit Multi-Unit Residential Buildings (MURBs) and install Level 2 Charging infrastructure in a portion of parking stalls in the province. Limited charging infrastructure in MURBs represents a key barrier to adoption in some jurisdictions, however the results indicated that this was not impactful nor cost-effective due to the housing composition of Newfoundland and Labrador market (i.e. less than 15% of the population residing in MURBs).

Table 6- 1. Levers Applied to the Newfoundland EV Adoption Scenarios (Under budget constraints)

Lever	Description	Low Scenario (≈ $5M investment)	High Scenario (≈ $20M investment)
DCFC deployment	Deployment of Public Direct Current Fast Chargers (DCFC) on highway corridors and in population centres	25 Stations (50 ports)	100 Stations (200 Ports)
L2 deployment	Deployment of Public Level 2 (L2) Charging in population centres	125 Stations (500 ports)	500 Stations (2000 ports)
Vehicle Incentives[56]	Rebates to customers to offset a portion of the upfront cost of an EV purchase	$5K incentive for LDVs, 10% incentive for MDV, HDV, Bus	$7.5K incentive for LDVs, 25% incentive for MDV, HDV, Bus

Figure 6- 11 and **Figure 6- 12** show the impact of the Low and High Investment of each lever on energy consumption compared to baseline,[57] and highlight the following takeaways:

- **Under both the low and high scenarios, DCFC and L2 deployment have the highest impact on adoption in both the short and long terms**. The limited availability of charging infrastructure in the province severely constrains market adoption of LDVs under baseline conditions, and any deployment increases both geographical coverage and availability of charging and has a significant impact on the market.
- **Although incentives boost adoption while they are in place, their impact is diminished once they are phased out.** Incentives can potentially increase EV load by 16 to 32% in the short-term through improving the business case of EV adoption and bridging the market to cost parity. Incentives contribute to both an increase in the number of EVs on the road as well as the shift from PHEVs to BEVs in the market, which corresponds to an increase in EV load. However, the results highlight that incentives cause a temporarily boost in adoption in the short-term, with a limited long-term market impact (8 to 9% increase).
- **Multi-unit residential building retrofits have limited impact due to the housing market composition in Newfoundland and Labrador.** Although limited charging infrastructure in MURBs represents a key barrier to adoption in some jurisdictions, the impact is less pronounced in Newfoundland due to less than 15% of the population residing in these housing types.
- **A portion of the impact from improved public charging infrastructure networks and incentives does not increase overall adoption, but rather results in a shift from PHEVs to BEVs.** Given this, the impact of investment on adoption is not proportional to impact on energy consumption.
- **Higher investments in DCFC and L2 Deployment can further increase market uptake of EVs in the province.** Expansion of public charging infrastructure has the potential to more than triple the number

[56] Incentives were assumed to step down gradually over time. Detailed assumptions can be found in Appendix D.

[57] Additional results in the appendix highlight the impact on EV adoption (i.e. number of vehicles on the road).

of EVs on the road to 132,000 EVs by 2034. This expansion is especially important as the EV population in the province grows in order to avoid congestion (i.e. lineups) at public charging stations.

Figure 6- 11. Impacts of Low Investment Scenario on EV Energy Sales ($5M)

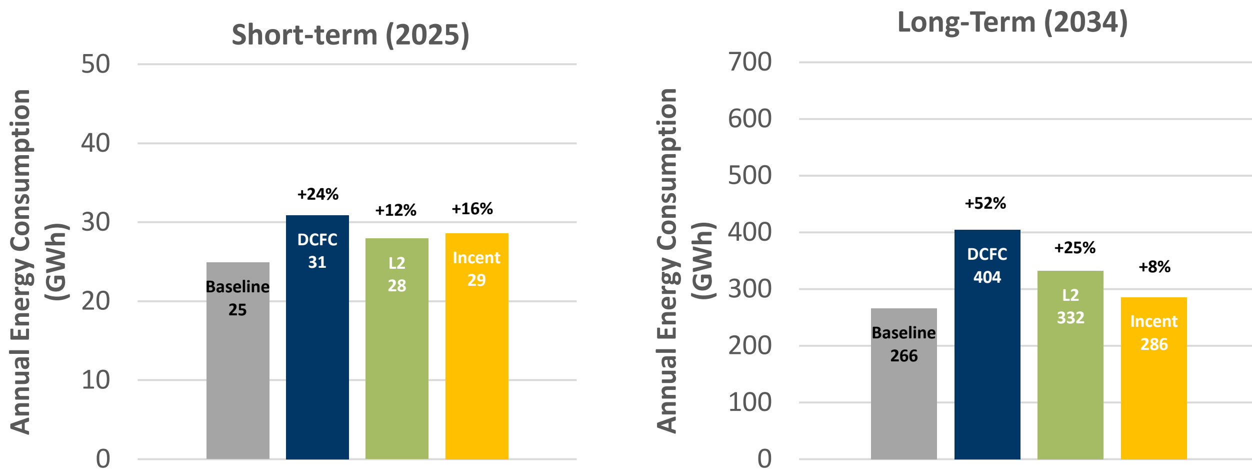
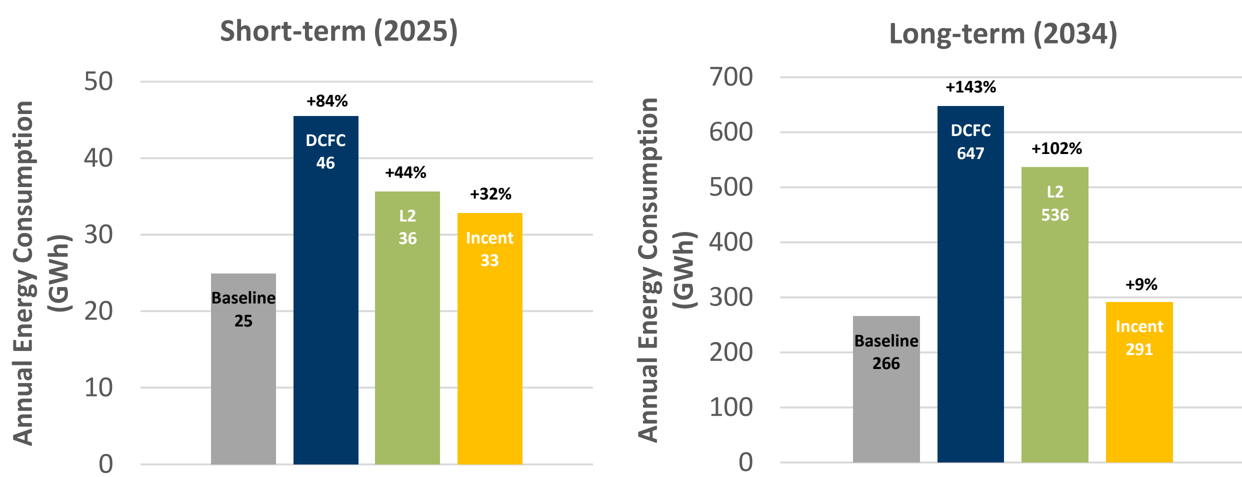


Figure 6- 12. Impacts of High Investment Scenario on EV Energy Sales ($20M)



COST-EFFECTIVENESS ASSESSMENT

For each of the modeled scenarios, the cost-effectiveness of an investment in the specified lever was calculated from the utilities' perspective.[58] The investments in these scenarios are assumed to take place over a 10-year period. To properly assess the financial feasibility of each option, however, the revenues and costs associated with the vehicles over the entire study-period (2020–2034) was used to capture the long-term cost-effectiveness of each initiative in a way that recognizes the life-time of the incremental sales revenues from supported EVs.

The impacts attributed to each scenario are assumed to be the incremental energy sales and peak capacity over the baseline scenario. The cost-effectiveness analysis then considered the following value-streams:

- **Benefits:** Revenues from incremental electricity sales based on forecasted electricity rates (mid scenario).[59]
- **Costs:**
    - Investment costs associated with each scenario
    - Cost of energy supply
    - Cost of capacity

Value streams were then discounted at the utilities' discount rate, and the Benefit to Cost Ratio (BCR) and Net Present Value (NPV) were calculated in order to assess cost-effectiveness from the utilities' perspective. Those scenarios with a BCR greater than 1 or a NPV greater than 0 are considered cost-effective. To obtain insights into the drivers behind cost-effectiveness of the different levers, cost-effectiveness was calculated under two cases:

- **Case 1**: Considering sales revenues and program and utility costs with unmanaged charging load
- **Case 2:** Considering sales revenues and program and utility costs with charging load management

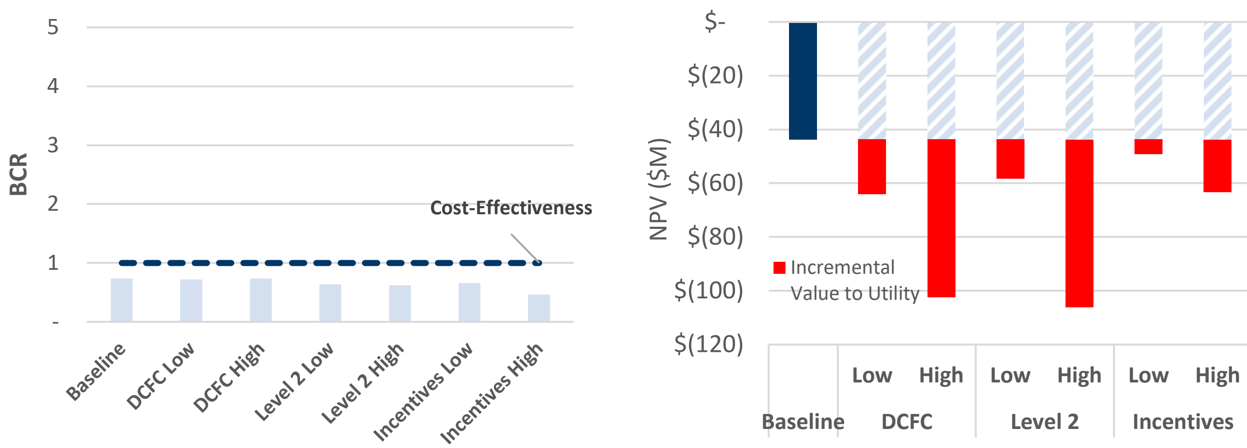
[58] Investments in MURB home charging programs were found not to be impactful or cost-effective in Newfoundland and Labrador, and were therefore removed from consideration in this section.

[59] The revenue calculations are based on the assumption that all the charging happens within the utilities' service territories. Additionally, charging rate is assumed to be a blended average of residential and commercial electricity rate projections under the mid scenario.

CASE 1

Considering utility revenues and costs, none of the levers were found to be cost-effective as shown **Figure 6- 13.** This is primarily due to high capacity costs, which diminish all revenue benefits that EVs bring to the utilities. Under baseline, the projected EV adoption is expected to result in -$44M value to the utilities. Any incremental investments that accelerate EV adoption result in a negative business case for the utilities and increase deficits.

Figure 6- 13. Cost-Effectiveness of Levers Assuming Unmanaged Charging Load

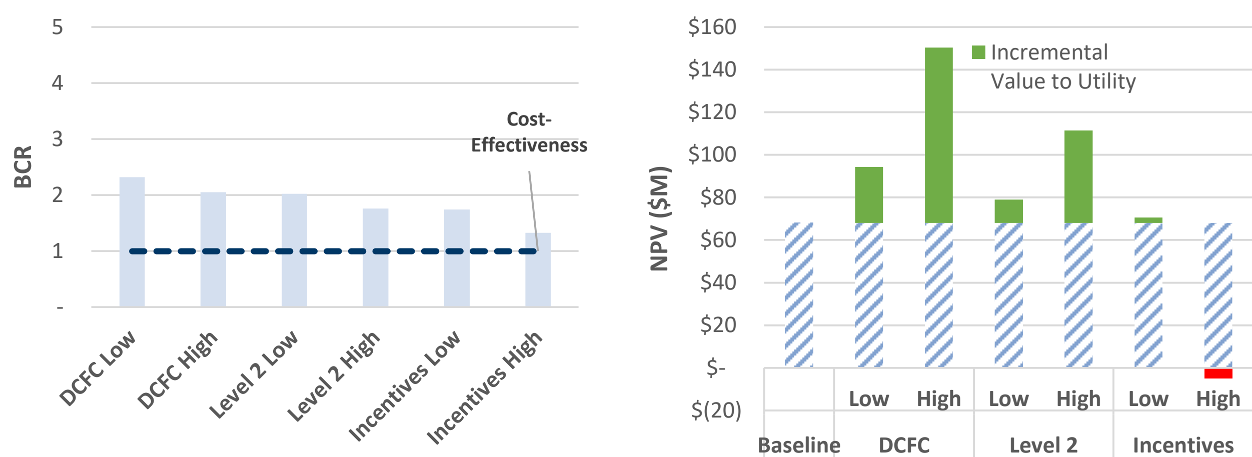


CASE 2

Contrary to findings under case 1, assuming load management is in place (which could reduce peak impacts of EV charging load by 85%) results in most levers being cost-effective from the utilities' perspective.[60] Under baseline conditions, EVs are estimated to increase energy sales nearly $70M in value by 2034. Investments can significantly increase that value. For example, a $20M DCFC deployment can bring in an additional $82M in additional value by 2034.

As shown in **Figure 6- 14**, DCFC and Level 2 infrastructure deployment are the most cost-effective options. The limited long-term market impacts of incentives result in significantly lower cost-effectiveness than infrastructure deployment. Additionally, the results show that over-investment in some interventions beyond a certain threshold (for ex: incentives or DCFC) may have diminishing returns. These impacts result in a lower BCR and NPV, as highlighted by the reduction in the BCR of the Incentives High Scenario relative to the Incentives Low Scenario; resulting in the lever not being cost-effective. The same trend is observed for DCFC investments, which had lower BCR for higher investments, suggesting that investments in infrastructure once the market is saturated have diminishing returns.

Figure 6- 14. Cost-Effectiveness of Levers Assuming Charging Load Management



[60] The cost- analysis does not consider the costs of managing and implementing an EV load management program.

SENSITIVITY TO CAPACITY COSTS

The tables below show results of the sensitivity analysis around capacity costs (considering 100%, 80% and 60% of costs) as well as the use of load management for the low and high investment scenarios respectively. The results confirm that reducing capacity load impacts of EVs will be critical to benefit from EV uptake in Newfoundland and Labrador. Even with a 40% reduction in capacity costs (i.e. 60% of current costs); some levers do have a slightly positive NPV, however have no or limited incremental value above baseline. Applying load management at the full capacity costs (i.e. Case 2 as shown earlier) results in significant cost reductions and maximizes the value of any investment the utilities make. Further capacity cost reductions under load management increase the value any investment can bring to the utilities.

Table 6- 2. Low Investment Scenario Sensitivity to Capacity Costs

NPV of Low Investment Scenarios						
Type of Charging	Unmanaged Charging			Load Management [61]		
Cost of Capacity (2019)	$430/kW (100%)	$340/kW (80%)	$250/kW (60%)	$430/kW (100%)	$340/kW (80%)	$250/kW (60%)
Baseline	($ 44M)	($ 17M)	$ 9M	$ 68M	$ 72M	$ 76M
DCFC	($ 64M)	($ 27M)	$ 10M	$ 94M	$ 100M	$ 106M
Level 2	($ 58M)	($ 26M)	$ 6M	$ 79M	$ 84M	$ 89M
Incentives	($ 49M)	($ 21M)	$ 7M	$ 71M	$ 75M	$ 79M

Table 6- 3. High Investment Scenario Sensitivity to Capacity Costs

NPV of High Investment Scenarios						
Type of Charging	Unmanaged Charging			Load Management [61]		
Cost of Capacity (2019)	$430/kW	$340/kW (-20%)	$250/kW (-40%)	$430/kW (100%)	$340/kW (80%)	$250/kW (60%)
Baseline	($ 44M)	($ 17M)	$ 9M	$ 68M	$ 72M	$ 76M
DCFC	($ 103M)	($ 43M)	$ 16M	$ 150M	$ 159M	$ 168M
Level 2	($ 106M)	($ 55M)	($ 4M)	$ 111M	$ 119M	$ 127M
Incentives	($ 63M)	($ 34M)	($ 4M)	$ 63M	$ 67M	$ 72M

[61] Assuming 85% of peak demand from EV charging load can be avoided.

CONSIDERATIONS FOR MARKET INTERVENTION

The results of the scenario analysis and estimation of impacts of each lever on adoption, load growth, and corresponding cost-effectiveness highlight the following key considerations for investments:

- **Market interventions can have a significant impact** on market uptake of EVs and bring load growth opportunities.
- **The commercial EV market is forecasted to be significant** with improving economics and will contribute to the majority of EV load in Newfoundland and Labrador.
- **High capacity costs coupled with the high coincidence between EV charging loads will result in significant deficits to the utility if load management is not utilized** to reduce peak charging and associated capacity costs.

ASSESSMENT OF INTERVENTION LEVERS

The assessment of the impact, cost-effectiveness and need for intervention for the four key intervention levers assessed in the scenario analysis highlights the following key considerations for investments:

- **DCFC Deployment:** Because the LDV market is severely constrained by the lack of public charging infrastructure, investments in DCFC will be the most impactful and cost-effective lever. The current lack of a solid business case for DCFC charging stations for third-party market actors suggests that DCFC deployment in the province will be limited in the absence of utility or government intervention. Despite the significant impact of DCFC deployment, the results highlight that over-investments in DCFC may have diminishing returns after the market is saturated, therefore DCFC investments should be prioritized while supporting the market through other levers. Additionally, utility deployment of charging infrastructure would also lead to benefits from optimizing station placement within the distribution system to avoid infrastructure upgrades.

- **L2 Deployment:** Although less effective than DCFC deployment in increasing adoption of EVs, public L2 deployment can support the increase of geographic coverage and availability of charging, helping to build confidence among potential EV buyers. A number of businesses across the province have already started deploying L2 charging stations at their facilities to attract EV drivers. Due to the lower installation and operational costs of L2 compared to DCFC, third-party deployment of L2 infrastructure faces fewer barriers and is likely to see more natural uptake. However, interventions may be needed to accelerate the pace of deployment of L2 in the short-term in order to alleviate charging barriers.

- **Vehicle Incentives:** The Federal EV purchase incentives are expected to support the growth of EVs in the province, however incremental incentives for LDVs may not have as significant of an impact on the market. Additionally, EV incentives are typically provided at the federal or provincial level and limited case studies of utilities providing EV purchase incentives are available.

- **MURB Home Charging:** Due to the housing market composition in the province and limited portion of the market living in MURBs, programs targeting retrofitting parking stalls in MURBs with home charging will have limited impact and likely not be cost-effective, and should therefore not be pursued. The upcoming Zero Emission Vehicle Infrastructure Program from NRCan can be leveraged by local governments and building owners to address this barrier.

SUGGESTED PRIORITY AREAS

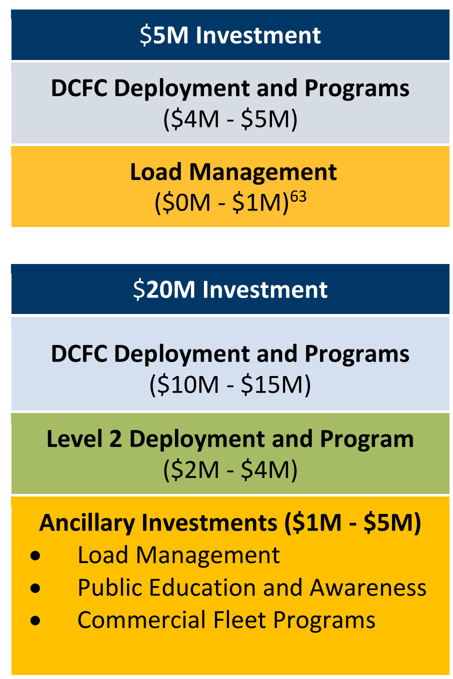
The results clearly highlight that DCFC deployment should be a priority as a means of accelerating EV adoption in Newfoundland and Labrador, increasing EV load growth**. Figure 6- 15** shows a sample investment strategy for a $5M and $20M investment options over a 10-year period.

Early investments should be mostly – if not fully – dedicated to DCFC deployment to ensure sufficient geographical coverage and availability of a charging network on key highway corridors and population centres across the province. **To maximize impacts of investments, existing federal programs can be leveraged (which currently offer up to 50% cost contribution)[62] to jump-start deployment of DCFC in the province. Additionally, rather than self-deployment of charging stations, the utilities can follow a "make-ready" approach where they develop infrastructure to enable the installations of DCFCs by third-parties (private corporations, municipalities, etc.) and potentially provide incentives to support the build-out of the charging stations.**

As indicated earlier, over-investments in DCFC deployment may have diminishing returns, therefore if a larger investment amount is available, investments should be diversified by complementing DCFC investments with Level 2 Infrastructure deployment and other initiatives including:

- **Load management programs:** Given the utilities' high capacity cost and high coincidence between charging load and utility peak, shifting charging load to off-peak hours will be critical to benefitting from the financial value that EV adoption can bring. The utilities can launch initiatives to encourage off-peak charging through smart charging (i.e. demand response with direct load control), Time-of-Use (TOU) rates, or other approaches.
- **Public marketing initiatives** to educate and raise awareness of the public about EVs and their benefits.
- **Commercial fleet programs:** A significant portion of the forecasted EV load growth in the province is expected come from commercial vehicles. The utilities can engage with fleet managers through utility account managers to inform about opportunities associated with fleet electrification and offer support through feasibility studies, financial support, and other means.

Figure 6- 15: Sample Investment Strategy



[62] Natural Resources Canada (NRCAN) Electric Vehicle and Alternative Fuel Infrastructure Deployment Initiative (EVAFIDI) and Zero Emission Vehicle Infrastructure Program (ZEVIP).

[63] Further analysis is required to assess the potential and costs of implementing different EV load management strategies under the forecasted adoption in Newfoundland and Labrador.

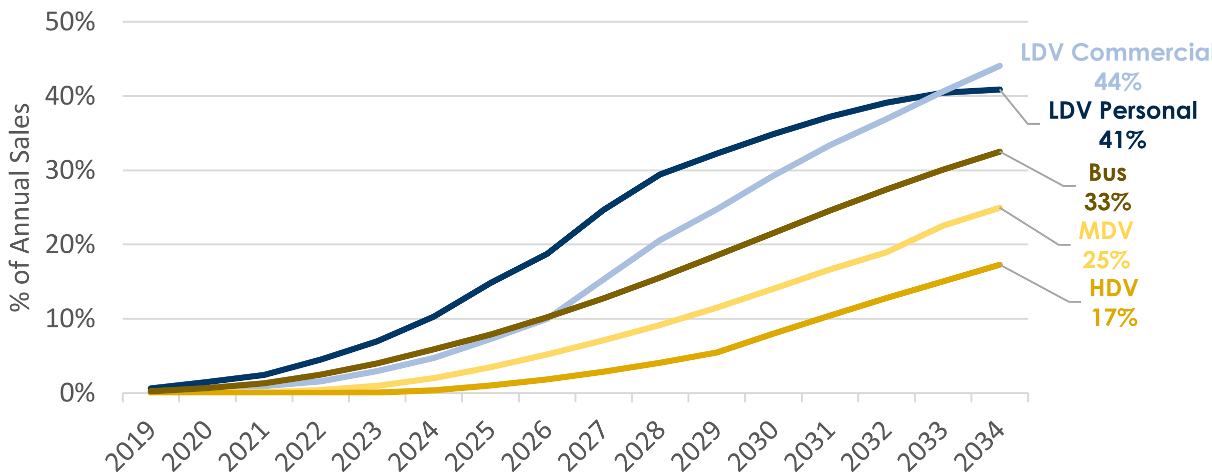
IMPACTS OF INVESTMENTS

Below, the potential impacts of the assumed $20M investments[64] on EV adoption are presented along with utility load and financial impacts.

Impact on Adoption: Compared to uptake under the baseline scenario shown earlier in **Figure 6- 4, Figure 6- 16** below shows that the modeled investment scenario will significantly increase LDV uptake in Newfoundland and Labrador, from 10% of sales in 2034 under baseline to 38% of sales by 2034. Under this scenario, EV adoption in Newfoundland and Labrador is on par with Canada-wide and global EV sales targets of 30% of sales by 2030. Investments can be scaled accordingly to reach more appropriate or desired levels of adoption in the province.

Interventions through public charging infrastructure deployment are not expected to move the medium- and heavy-duty vehicle market. With the exception of long-haul trucking that may depend on a network of charging stations, MDV and HDV segments are mostly expected to rely on depot charging. Generally, MDV, HDV and buses were found to be more sensitive to economics and will require substantial support in the form of incentives or changes in key market economic factors (electricity rates, fuel prices, etc.) to trigger any significant shift in adoption beyond natural market uptake. Programs targeted towards commercial fleets, awareness campaigns and other initiatives could be potential levers to accelerate the commercial market.

Figure 6- 16. Percent of Electric New Vehicle Sales by Vehicle Class Under $20M Investment Scenario



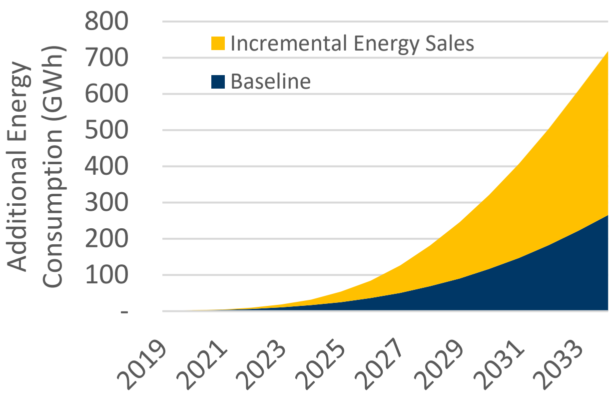
Load Impacts: As shown in **Figure 6-17**, the incremental adoption attributed to the investments can almost triple load growth from EVs relative to baseline (+175%) to 720 GWh of energy consumption (approximately a 7% increase in 2034 energy consumption). Under unmanaged charging, EV charging is expected to increase system peak demand by 281 MW (approximately a 13% increase in 2034 peak load). EV charging is an inherently flexible

---

[64] The proposed $20M investment scenario assumes utilities only cover 50% of the cost of DCFC and L2 deployment, either through leveraging external funding for 50% of project costs or supporting third-parties through a 50% incentive. Additional results in Appendix F show the impact of the proposed $5M investment focused on DCFC that assumes the same 50% utility contribution to costs.

load and can be managed to a large extent through load management and smart charging techniques. At least one smart charging pilot conducted by a Canadian electric utility demonstrated that 85% of charging load could be consistently shifted to off-peak hours, even while providing EV drivers the opportunity to override utility requests.[65] More granular analysis is required to assess the potential for shifting EV load in the Newfoundland and Labrador system, however assuming 85% of peak charging can be mitigated, only a 42 MW increase in peak demand will be observed as a result of EV charging as shown in **Figure 6- 18.**[66]

Figure 6- 17. Energy and Peak Load Impacts from Electric Vehicle Adoption Under $20M Investment Scenario



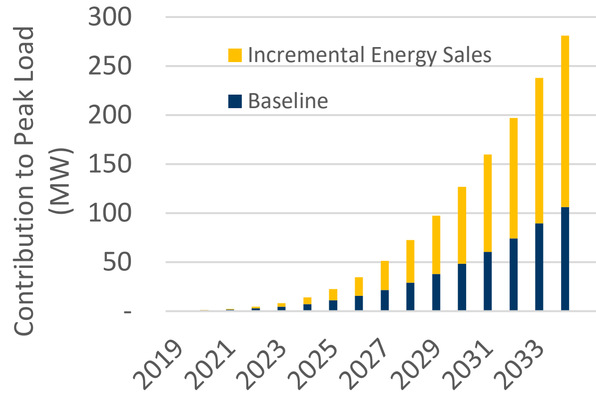
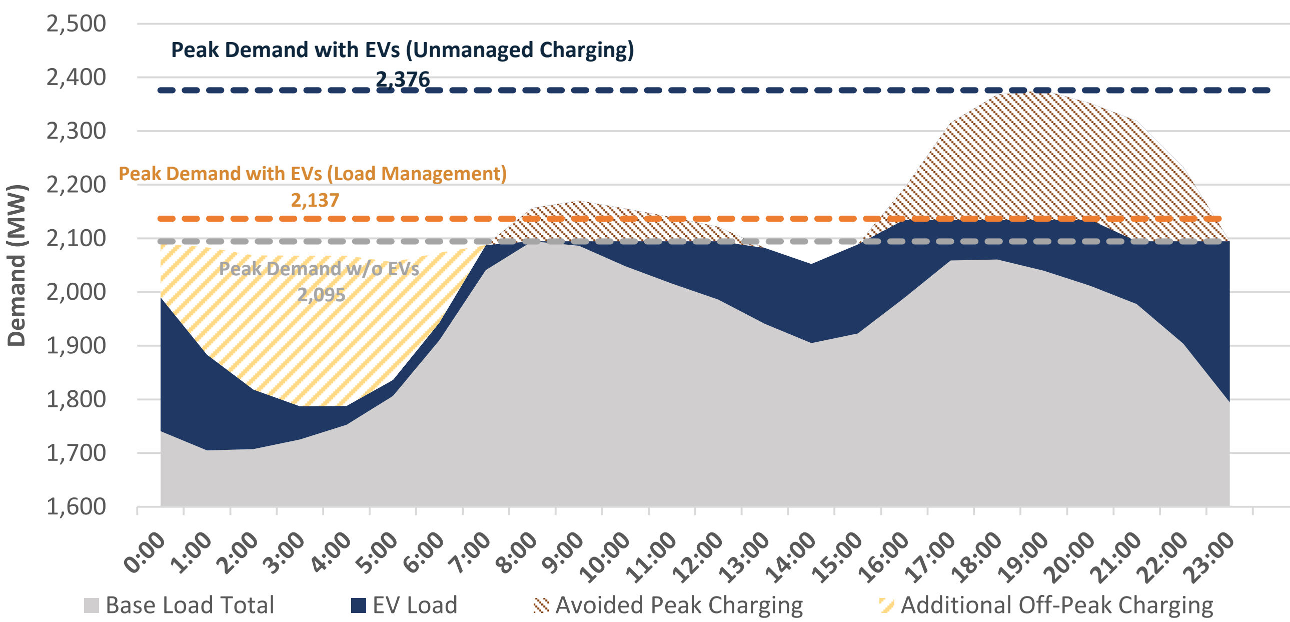


Figure 6- 18. Peak Load Impacts Under $20M Investment Scenario



---

[65] Final report for the "ChargeTO" Residential Smart Charging Pilot in Toronto, conducted by FleetCarma in partnership with Toronto Hydro. https://www.fleetcarma.com/resources/chargeto/

[66] The shown charging load shifting to off-peak hours is for illustration purposes only. A more detailed analysis of the potential for load shifting in the Newfoundland and Labrador Systems is required to identify the magnitude of peak reduction can be achieved.

Financial Impacts: By 2034, the modeled $20M would nearly triple revenues from EV deployment, from $119M under baseline to $317M. However, without load management, the additional revenue is diminished by the high peak impacts and capacity costs, resulting in a net loss of $44M. Load management can allow the utilities to benefit from the revenue generated from EV energy sales while reducing capacity costs significantly. The modeled $20M would increase the value of EV deployment to the utility to $170M ($102M over baseline). This net revenue gain to the utilities may contribute to Utility efforts to mitigate projected electricity rate increases stemming from the Muskrat Falls generation facility.

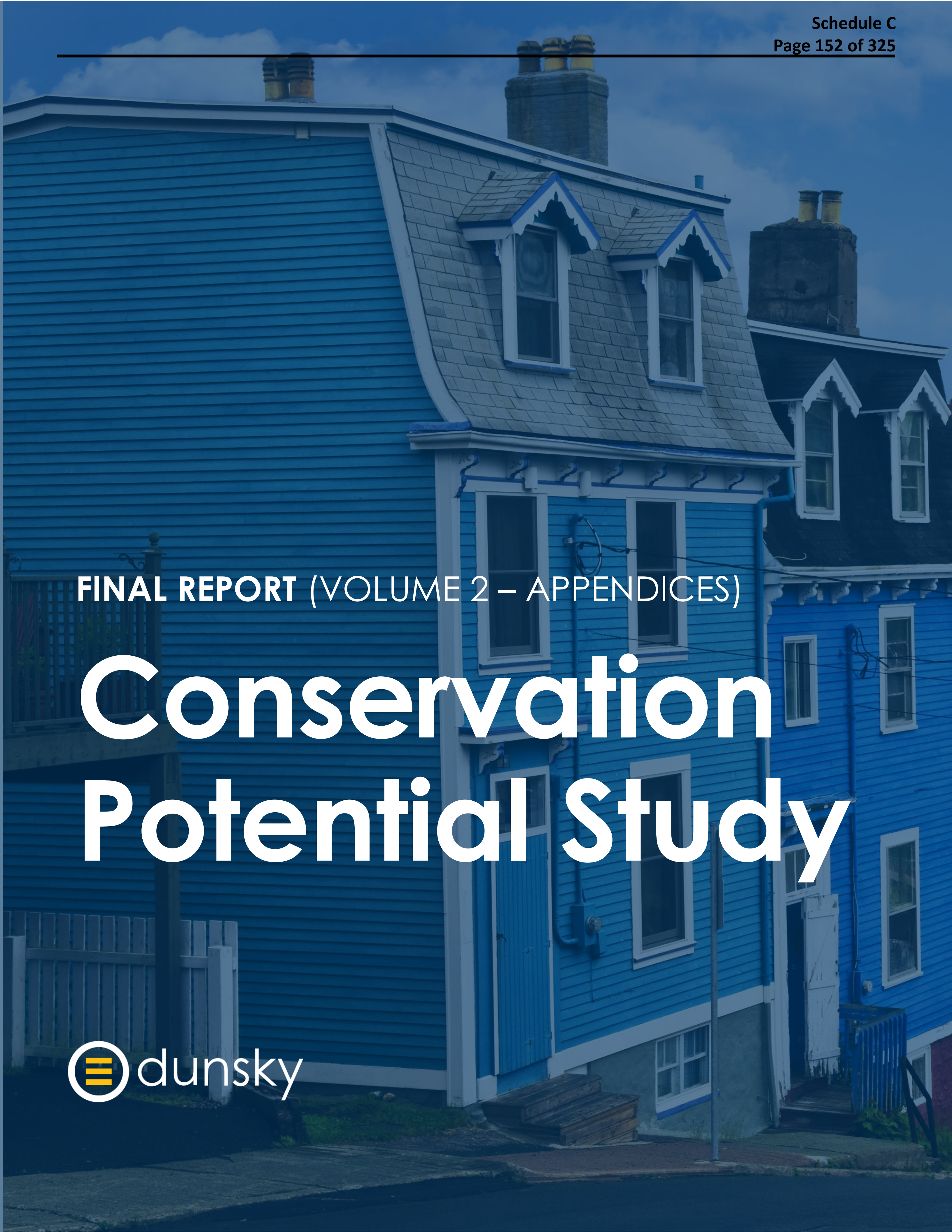
Table 6- 4. Benefits and Costs of EV Adoption Under Baseline and $20M Investment Scenario By 2034

	Unmanaged Charging			Load Management		
	Benefits	Costs	NPV	Benefits	Costs	NPV
Baseline	$119M	($163M)	**($44M)**	$119M	($51)	**$68M**
$20M Investment	$317M	($359M)	**($113M)**	$317M	($147M)	**$170M**

EV ADOPTION: KEY TAKE-AWAYS

The study of the potential and impacts of EVs in Newfoundland and Labrador highlights the following key takeaways:

- **Under baseline, adoption of EVs in Newfoundland and Labrador by 2034 is forecasted to be limited with approximately 41,400 EVs on the road by 2034**. Particularly, projections for LDVs sales in Newfoundland and Labrador are well below national and global projections. This is primarily caused by lack of public charging infrastructure, which is forecast to significantly constrain the growth of the LDV market moving forward. Despite the early lead of personal LDVs, commercial vehicles are expected to significantly increase in share during the study period as a result of improving economics. As opposed to LDV projections, the forecast uptake of MDVs and HDVs in Newfoundland and Labrador are on par with global ones. Overall, under the baseline scenario EVs are estimated to add 266 GWh of electricity consumption by 2034 (≈ 3% of energy sales) and contribute to a 106 MW increase in the utilities' peak demand (≈ 5% of forecast peak by 2034). The majority of the forecast load impacts are attributed to the commercial EVs on the road.
- **Investments can have a significant impact on accelerating EV adoption and corresponding energy sales, as much as tripling load growth from EVs by 2034 under the modeled hybrid $20M investment.** DCFC deployment has been identified as a priority for any investment, as it is the most impactful and cost-effective lever. For example, a $20M investment in DCFC infrastructure would result in 132,000 EVs on the road (219% increase from baseline), and 647 GWh of EV load by 2034 (143% increase from baseline). However, investments in DCFC beyond certain thresholds may result in over-saturation and are expected to have diminishing returns. This suggests that investments should be diversified by complementing investments in DCFC with public L2 deployment, education and awareness initiatives and programs targeted towards commercial fleets. Although incentive programs could accelerate adoption in the short-term, they have limited long-term impact on the market and may not be a suitable approach for intervention.
- **The utilities' high capacity costs coupled with the coincidence between EV charging and utility loads will likely lead to significant peak increases and costs to the utilities if load management is not utilized or capacity costs are not reduced.** Under baseline conditions, the utilities are forecast to incur losses of $44M by 2034 as a result of EV deployment. Additionally, most investments that accelerate EV adoption (i.e. DCFC deployment, etc.) will have negative returns under the existing capacity costs and unmanaged charging loads and will further increase losses. This is primarily due to the utilities' high capacity costs¸ and if EV load management can be deployed the financial impacts could change significantly.
- **EV charging load management will be critical to handle the system impacts of EVs and benefit financially from EV adoption under baseline scenario as well as any investment scenario.** With load management, 85% of peak charging is estimated to be shifted to off-peak hours. A modeled $20M investment focused on DCFC and L2 infrastructure can bring more than $170M in additional value by 2034 in the presence of load management versus a loss of $113M under an unmanaged charging scenario. This corresponds to an increase in peak demand of 42 MW under a load management scenario (approximately 2% of forecast 2034 peak demand), whereas unmanaged load scenario would contribute to 281 MW of additional peak load (13% of forecasted 2034 peak demand). The utility should thus prioritize initiatives that can reduce peak impacts of EV loads and consider more granular analysis to assess the specific potential and costs associated with shifting EV load in the Newfoundland and Labrador system.



FINAL REPORT (VOLUME 2 – APPENDICES)

Conservation Potential Study

dunsky

Conservation Potential Study
Final Report, Volume 2

Submitted to:

Newfoundland Power Inc.
Newfoundland and Labrador Hydro

Prepared by:

Dunsky Energy Consulting (6893449 Canada Inc.)

Contact:
Alex J. Hill
Managing Partner
50 Ste-Catherine St. West, suite 420
Montreal, QC H2X 3V4

T: 514 504 9030 ext. 30
E: alex.hill@dunsky.com

CONTENTS

LIST OF FIGURES

LIST OF TABLES

LIST OF ACRONYMS

ASHP – Air Source Heat Pump

BEV – Battery Electric Vehicle

BUG – Backup Generator

CBR – Cost Benefit Ratio

CDM – Conservation and Demand Management

CEUS – Commercial End-Use Survey

CPP – Critical Peak Pricing

CVR – Conservation Voltage Reduction

DCFC – Direct Current Fast Charger

DEEP – Dunsky Energy Efficiency Potential Model

DHW – Domestic Hot Water

DMSHP – Ductless Mini-Split Heat Pump

DR – Demand Response

EE – Energy Efficiency

ER – Early Replacement

EUL – Estimated Useful Life/Effective Useful Life

EVA – Electric Vehicle Adoption Model

RCx – Retro-commissioning

FS – Fuel Switching

GHG – Greenhouse Gas

GWh – Gigawatt Hour

HDV – Heavy Duty Vehicle

HVAC – Heating, Ventilation, and Air-Conditioning

ICE – Internal Combustion Engine

IIC – Island Interconnected System

IOC – Iron Ore Company of Canada

ISO – Isolated Diesel System

ISP – Industry Standard Practice

kWh – Kilowatt Hour

L2 – Level 2

LAB – Labrador Interconnected System

LDV – Light Duty Vehicle

LED – Light-Emitting Diode

MDV – Medium Duty Vehicle

MW - Megawatt

MWh – Megawatt Hour

NTGR – Net-to-Gross Ratio

PACT – Program Administrator Cost Test

PC – Participant Cost

PCT – Participant Cost Test

PHEV – Plug-in Hybrid Electric Vehicle

ROB – Replace on Burnout

RUL – Remaining Useful Life

SCT – Societal Cost Test

SEM – Strategic Energy Management

TCO – Total Cost of Ownership

TOU – Time-of-Use

TRC – Total Resource Cost

TRM – Technical Reference Manual

VFD – Variable Frequency Drive

VRF – Variable Refrigerant Flown

DEFINITIONS

Assessment of potential: The development of energy and capacity savings available from projected customer usage through the application of commercially available, cost-effective technologies and improved operating practices, considering the impacts of market factors.

Achievable potential: The savings from cost-effective opportunities once market barriers have been applied, resulting in an estimate of savings that can be achieved through demand-side management programs. Three achievable potential scenarios were modeled to examine how varying factors such as incentive levels and market barrier reductions impact uptake.

Cumulative savings: A rolling sum of all new savings that will affect energy sales, cumulative savings exclude measure re-participation (i.e. savings toward a measure are counted only once, even if customers can participate again after the measure has reached the end of its useful life) and provide total expected grid-level savings.

Economic potential: The savings opportunities available should customers adopt all cost-effective savings, as established by screening measures against the Total Resource Cost (TRC) test, without consideration of market barriers or adoption limitations.

Energy End-Use: In this study, energy end-uses refer to grouping of energy saving measures related to specific building component (i.e. water heating, HVAC, lighting etc.)**.**

Energy Saving Measure: An energy saving measure (or measure) refers to a specific equipment or building operation improvement that leads to energy savings.

Market Sector: The market of energy using customers in Newfoundland and Labrador is broken down into two sectors based on the primary occupants in the building: Residential (including single family and multi-family buildings) or Commercial (including businesses, institutional and industrial buildings).

Market Segment: Within each Sector, market segments are defined to capture key differences in energy use and savings opportunities that are governed by building use and configuration.

NL Utilities: Refers to the two retail utilities in Newfoundland and Labrador, Newfoundland Power (NF Power) and Newfoundland and Labrador Hydro (NL Hydro).

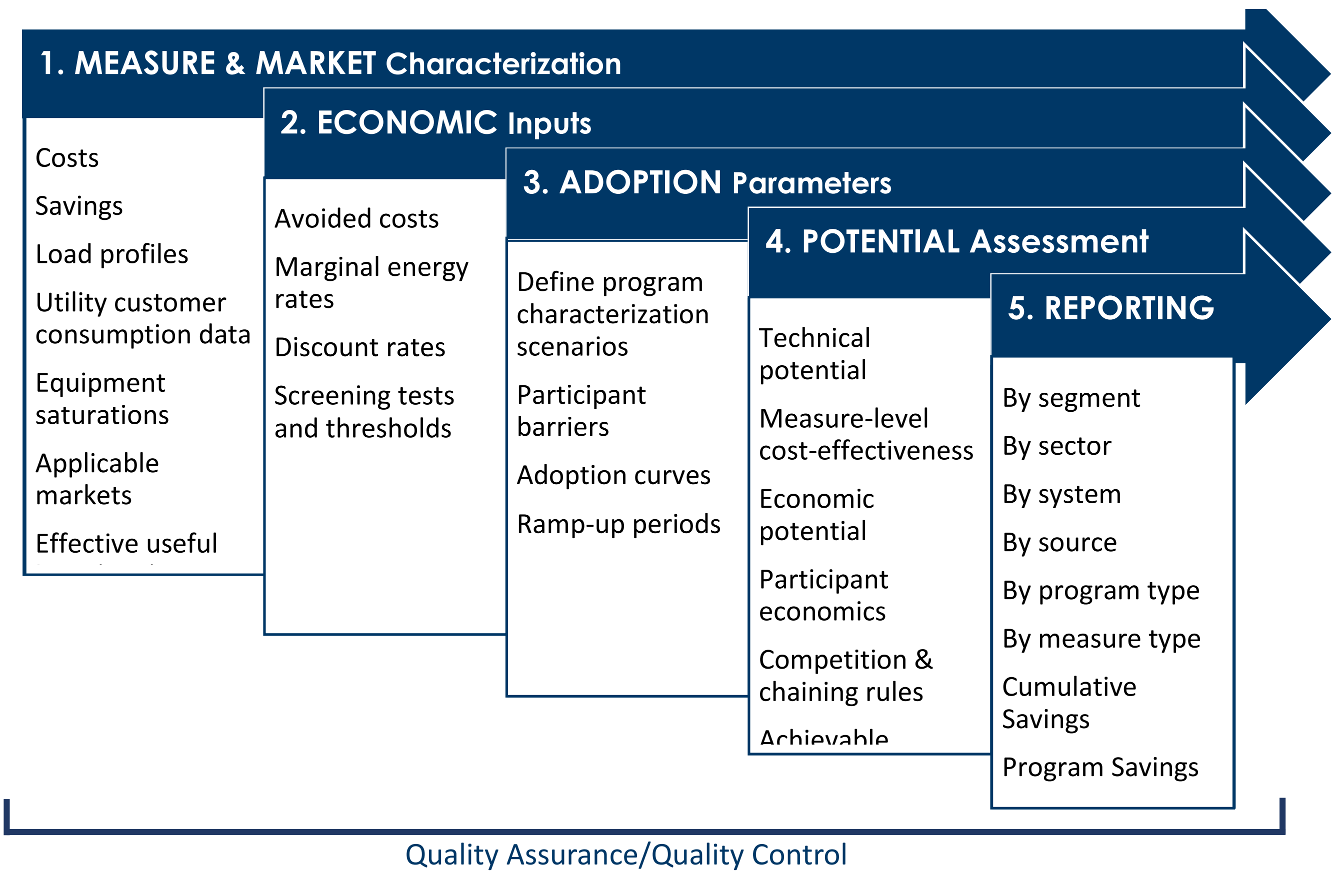
Program savings: Savings from measures that are incentivized through programs in a given year, including savings from measure re-participation. They are most representative of annual program savings and can be used to improve CDM program planning to help meet savings objectives, and to determine which sectors, end-uses, and measures hold the most potential.

Technical potential: The theoretical maximum savings potential, ignoring constraints such as cost-effectiveness and market barriers.

APPENDIX A: DUNSKY ENERGY EFFICIENCY POTENTIAL (DEEP) MODEL METHODOLOGY

The Dunsky Energy Efficiency Potential (DEEP) model employs a multi-step process to develop a bottom-up assessment of the Technical, Economic and Achievable Potentials. The process begins by establishing a comprehensive set of inputs related to energy savings measures, markets, equipment saturations, and economic factors, which are then applied in the model to assess energy savings potential. This appendix outlines the key features of the modelling technique, including the calculation methodologies employed, and the steps taken to ensure the accuracy and quality of the final results and reporting. **Figure A- 1** below provides a high-level overview of the key assessment steps and inputs, followed by more details throughout this appendix.

Figure A- 1. Key steps and inputs in study methodology



The key steps in the DEEP modelling process are:

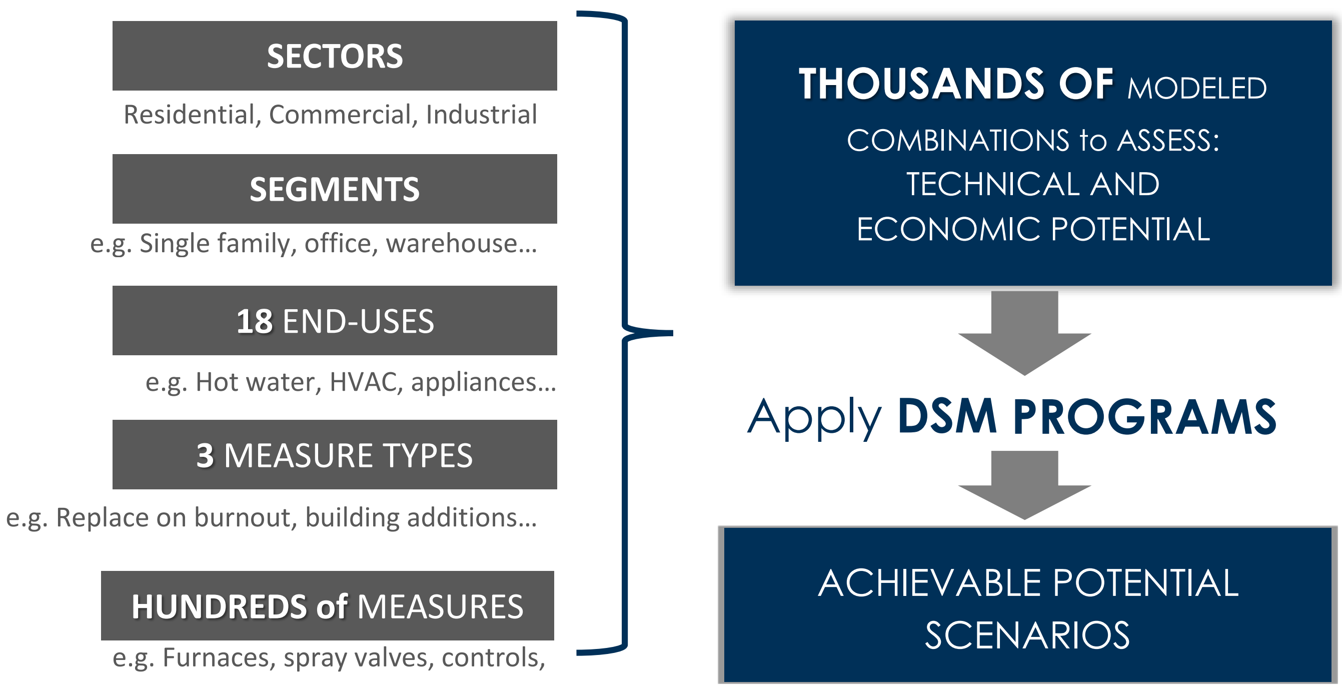
- **Characterize Measures and Their Applicable Markets:** A comprehensive list of energy saving measures is characterized by applying jurisdiction-specific data and assumptions to each measure and market segment. Primary and secondary data are compiled (as available) to establish an assessment of the market baseline, detailing the current saturation of energy using equipment in each market sector and segment. Markets for energy measures are then assessed by combining utility customer counts with market growth factors, equipment turnover rates, and the market baseline results.
- **Economic Inputs:** The model harnesses key economic inputs to assess the measure cost-effectiveness and benefits. Utility avoided costs, customer discount rates, energy rates, and the utility cost of capital are captured and entered into the model in real dollars based on the study period start year. The cost-effectiveness test that will be applied for economic screening is selected, as well as the other test that will be calculated to benchmark program performance.
- **Adoption Parameters:** For each measure-market combination adoption curves are assigned based on customer barrier level assessments. Customer economics inputs such as measure savings, marginal electricity rates and other secondary energy sources are applied to calculate the participant cost test (PCT), the key driver of adoption levels in each adoption curve. Finally, program characterizations are entered into the model by defining the fixed and variable program costs, incentive levels, and enabling activity impacts on customer barriers.
- **Potential Assessment:** The DEEP model assesses the technical potential by combining the measure characterization with the market baseline inputs to determine the theoretical maximum amount of savings possible for each measure-market combination, in each year, over the study period. Measures-market combinations that pass the cost-effectiveness threshold are counted in the economic potential. Achievable potential scenarios are applied by calculating the customer economics, under various incentive program scenarios, and applying adoption curves as described later in this Appendix. At each level, the model applies chaining factors to account for interactive effects among measures and assigns the appropriate market portion in places where multiple measures may compete for the same market (e.g., Tier 1 and Tier 2 efficiency heat pumps).
- **Reporting:** Reporting is conducted in four steps, from the presentation of the initial Draft Results to the Final Report, each with an increasing level of precision and detail. Each report is vetted by the relevant parties, and all feedback is considered and incorporated into the model and reporting before proceeding to the next step.
- **Quality Assurance / Quality Control (QA/QC):** Throughout the modeling process, a rigorous QA/QC process is applied to ensure the inputs reflect the energy using equipment in the studied jurisdiction, and that the results provide an accurate assessment of the energy savings potential. The model is calibrated to past DSM program performance and benchmarked to the baseline energy sales projections and individual energy end-uses, to ensure that the technical, economic and market factors align with the local reality.

DEEP'S BOTTOM-UP ASSESSMENT OF POTENTIAL

DEEP's bottom-up modelling approach assesses each measure-market segment combination, applying CDM programs to arrive at a fulsome assessment of the energy savings potentials. Rather than estimating potentials based on the portion of each end use that can be reduced by energy saving measures and strategies (often referred to as a Top-Down analysis), the DEEP model's Bottom-Up approach applies a highly granular calculation methodology to assess the energy savings opportunity for each measure-market segment opportunity in each year. Key features of this assessment include:

- **Measure-Market Combinations:** Equipment saturations, utility customer counts, and demographic data are applied to create "markets" for each individual measure. The savings per year, and the market size are unique for each measure-market segment combination, thereby increasing the accuracy of the results.
- **Phase-In Potential:** The DEEP model applies the equipment expected useful life (EUL) and market growth factors to determine the number of energy savings opportunities for each measure-market combination in a given year. This provides an important time series for each energy savings measure, upon which estimated annual achievable program volumes (measure counts and savings) can be calculated in the model, as well as phase-in technical and economic potentials.
- **Annual and Lifetime Savings:** For each measure-market combination in each year, DEEP calculates the annual savings as well as the lifetime savings, accounting for mid-life baseline adjustments where appropriate. This provides a read on the cumulative savings (above and beyond natural uptake), as well as the annual savings that will pass through DSM portfolios.

Figure A- 2.Bottom-up Combinations in the DEEP Model (A Separate Model was Created for Each NL Electric System)



OVERVIEW OF MODELLING CALCULATIONS

The DEEP model assesses three levels of energy savings potential: technical, economic, and achievable. In each case, these levels are defined based on the governing regulations and practice in the modeled jurisdiction, such as applying the appropriate cost-effectiveness tests, and applying the relevant benefit streams and net-to-gross (NTG) ratios to ensure consistency with evaluated past program performance.

- **Technical Potential:** The technical potential accounts for all theoretically possible energy savings stemming from the applied measures. In markets where multiple measures may compete,[1] the measure procuring the most energy savings per unit is selected.
- **Economic Potential:** The economic potential includes all measures that pass the cost-effectiveness test screen. Economic screening is performed at the measure level, and only accounts for direct costs related to the measure, not including general DSM program costs.
- **Achievable Potential:** The achievable potential considers customer barriers and economics to assess the annual adoption of measures within DSM programs. Achievable potential scenarios are applied based on the removal of barriers (incentives and enabling activities).

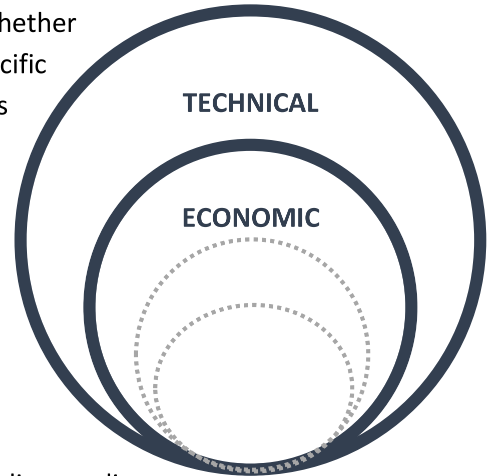
Figure A- 3.Bottom-up combinations in the DEEP Model

APPLIED CALCULATION	TECHNICAL POTENTIAL	ECONOMIC POTENTIAL	ACHIEVABLE POTENTIAL
1. ECONOMIC SCREENING	No Screen	Cost-Effectiveness (TRC)	Cost-Effectiveness (TRC and PCT)
2. MARKET BARRIERS	No Barriers (100% Inclusion)	No Barriers (100% Inclusion)	Market Barriers (Adoption Curves)
3. COMPETING MEASURES	Winner takes all	Winner takes all	Competition Groups Applied
4. MEASURES INTERACTIONS	Chaining Adjustment	Chaining Adjustment	Chaining Adjustment
5. NET SAVINGS	Not Considered	Not Considered	Program NTGR

[1] The words “market” or “market size” are used to describe the number of baseline equipment or buildings in a given segment that capture the opportunity for specific energy-efficient measures. For example, the number of sockets with incandescent bulbs in the single-family residential sector would be an example of a “market” for CFLs or LEDs.

CALCULATION OF TECHNICAL AND ECONOMIC POTENTIAL

Various calculation methods are applied at different levels of potential, whether technical, economic, or achievable. These are based on each measure's specific characterization (cost-effectiveness, market applicability), as well as interactive and competition effects among measures.



The calculations applied at the technical and economic levels of potential assessment are outlined below. Calculations are conducted independently at each level to account for shifting and dynamic measure mixes and interactive effects at each level.

TECHNICAL POTENTIAL

Technical potential is the theoretical maximum savings opportunity, disregarding constraints such as cost-effectiveness and market barriers. This excludes early replacement and retirement opportunities, which are to be addressed in the subsequent *achievable* potential analysis.

The measure procuring the most energy savings per unit for each sub-sector and end-use is selected, which maximizes overall energy savings. The focus of the technical potential is on energy savings (e.g., the measures selected are based on energy savings, although demand savings are also calculated). The measures applied in the model are outlined in the approved study measure list (included in Appendix E).

Phase-in Technical Potential: The technical potential, and all other potential levels are calculated on an annual phase-in basis to determine the size of the available market in each year. For each measure for each year, the calculation applies the market size and growth factors, measure type, early and natural replacement rates of existing equipment, and the maximum number of units that could be replaced or installed for a given measure.

ECONOMIC POTENTIAL

Economic potential is determined by screening technical potential measures – or bundles of measures – against the applicable standard cost-effectiveness tests. It disregards market barriers to adoption.

The model can apply any standard cost-effectiveness test, and adaptations are made to follow local jurisdiction cost-effectiveness testing requirements. The threshold for screening is set at 0.8 for the TRC (i.e., measures that achieve a higher cost-effectiveness test result are counted in the economic potential) but can be adjusted in the model to test various screening regimes. Tests included in the model are:

- **Total Resource Cost (TRC) Test**
- **Program Administrator Cost Test (PACT)**
- **Participant Cost Test (PCT)**

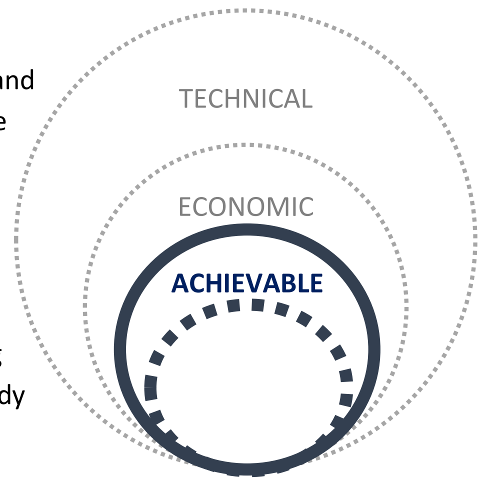
Table A- 1: Costs and Benefits that May be Applied for Cost-Effectiveness Screening

Benefits	Costs
• Utility avoided costs (TRC, PACT) • Customer avoided energy costs (PCT)	• Incremental measure costs (TRC, PCT) • Incentive Costs (PACT)

When calculating the inputs above, and indeed throughout the DEEP model, Dunsky applies the following:

- **Lifetime Benefits:** All benefits applied in the cost-effectiveness test are multiplied by their corresponding cumulative discounted avoided costs to get a present value ($) of lifetime benefits.
- **Real Dollar Accounting:** All benefits and costs are adjusted to real dollars, expressed in the first year of the study (unless otherwise requested).

ACHIEVABLE POTENTIAL SCENARIO ASSESSMENT



The achievable potential is the estimated amount of energy and demand savings that can be achieved by the portfolio of DSM programs applied to the market. **Market adoption is assessed by applying the PCT along with the market adoption curve** associated with the assigned market barrier level for each measure.

Various scenarios are applied by modifying the enabling activities, specifically the incentive levels and barrier reductions from enabling activities. Achievable potential scenarios are defined according to the study requirements.

DSM PROGRAM ARCHETYPES

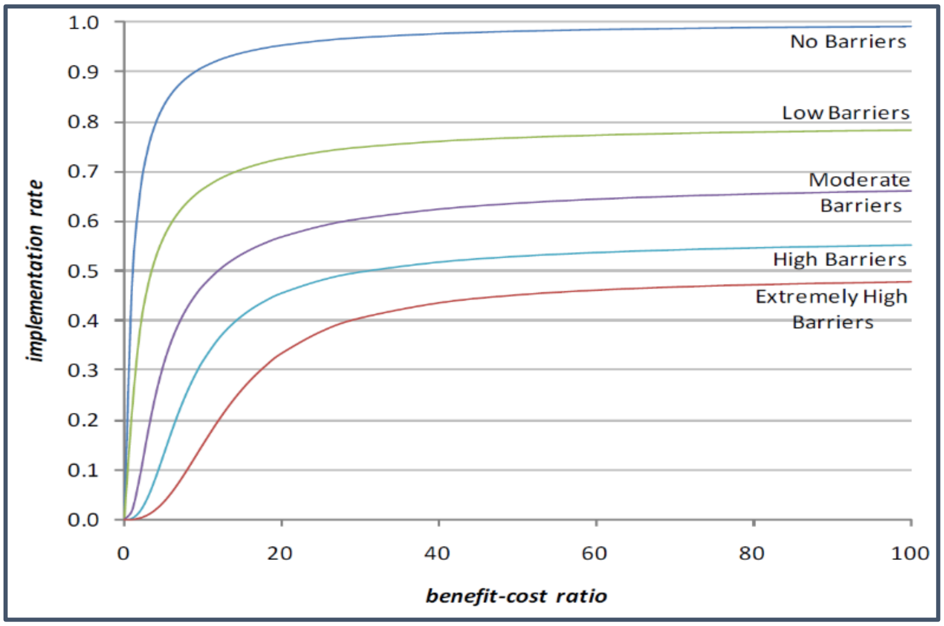
The achievable potential scenarios are assessed by applying DSM program archetypes that are developed based on an analysis of local DSM program evaluation reports, best practices from other jurisdictions, and through discussion with the DSM program administration team(s). Characterization of each program includes translating enabling strategies into customer barrier reduction impacts, incentive levels, cost structure, and applicable measures; those measures are mapped into the potential model. The model's bottom-up calculation approach is used to obtain costs, savings and average persistence of energy savings at the program level by aggregating measures by program archetypes using program assumptions.[2]

[2] While these high level assumptions are used in the model, the Utilities will complete detailed program design after the study is completed, and some programs may be screened out based or deemed not cost effective based on this

DEEP'S REFINED ADOPTION RATE METHODOLOGY

Rooted in the United States' Department of Energy (U.S. DOE) adoption curves,[3] the model methodology sets adoption rates based on a combination of customer cost-effectiveness – applied differently for each sector – and levels of market barriers. **Figure A- 4** presents a schematic view of resulting adoption curves. Five levels of barriers, to which measure categories are assigned based on market research or professional experience, define the maximum adoption curves. Different end-uses and segments exhibit different barriers.

Figure A- 4.Adoption Curves Used in the Study



The DEEP model applies five steps to determine the achievable potential:

1. **Barriers:** Assign each measure category, within each segment, to one of five adoption curves based on its assumed market barrier level (these can change over time if market transformation effects are anticipated).
2. **Drivers:** Assign cost-effectiveness metrics to each sector based on market research into economic drivers or professional experience.
3. **Incentives:** Assign assumed incentive levels.
4. **Economics:** Calculate customer cost effectiveness expressed by the PCT.

in-depth program design.

[3] The USDOE uses this model in several regulatory impact analyses. An example can be found in http://www.regulations.gov/contentStreamer?objectId=090000648106c003&disposition=attachment&contentType=pdf, section 17-A.4.

5. **Adoption:** Calculate resulting adoption rates and adjust as needed based on other external influences such as the ramp-up period (see *Refinement #2* in the call-out box below).

While this methodology is rooted in the U.S. DOE's extensive work on adoption curves, it applies two important refinements, as described in the call-out box below.

Refinements to U.S. DOE Adoption Curves

Refinement #1: Choice of the cost-benefit criteria. The DOE model assumes that participants make their decisions based on a benefit-cost ratio calculated using discounted values. While this may be true for a select number of large, more sophisticated customers, experience shows that most consumers use simpler estimates, including payback periods. This has implications for the choice and adoption of measures, since payback period ignores the time value of money as well as savings after the break-even point. The model converts DOE's discount rate-driven curves to equivalent curves for payback periods.

Refinement #2: Ramp-up. Two key factors – measure awareness and program delivery structure – can in theory limit program participation, especially during the first few years after a program's launch, and result in lower participation than DOE's achievable rates would suggest. For example, a new home retrofit program that requires the enrollment and training of skilled auditors and contractors by program vendors could take some time to achieve the uptake assumed using DOE's curves. In this study, we have therefore applied an adjustment to select programs on a case-by-case basis.

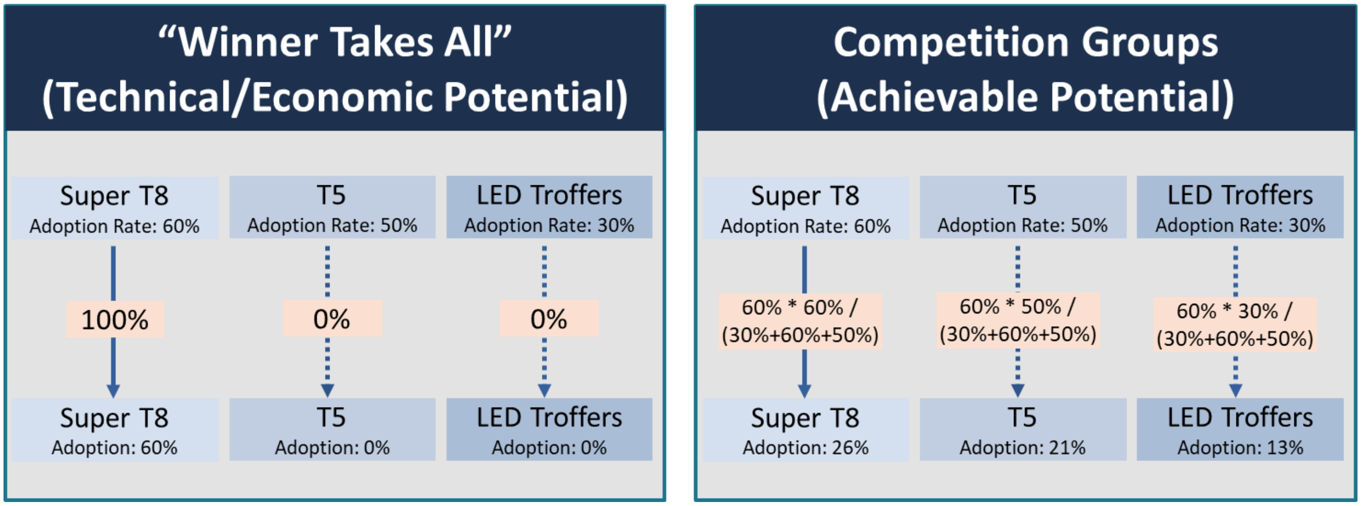
COMPETING MEASURES

Competing measures share the same market opportunity but are mutually exclusive. Examples include ground-source heat pumps vs. air-source heat pumps, or LED troffers vs. T5 lamps. In these cases, the DEEP model assesses the market for each depending on the potential level as follows:

- **TECHNICAL POTENTIAL**: 100% of the market is applied to the measure with the highest savings.
- **ECONOMIC POTENTIAL**: 100% of the market is applied to the *cost-effective* measure with the highest savings.
- **ACHIEVABLE POTENTIAL**: All cost-effective measures compete for the same market. Assuming that all measures are cost-effective, each adoption rate will be a pro-rated value based on the maximum adoption rate and each of the measures' respective adoption rates.

Below is an example where three measures compete: LED troffers, Super T8 and T5 lamps. First, the adoption rate is calculated for each measure independent of any competing measures, as outlined in the figure below.

Figure A- 5. Competing Measures Overview



From this assessment, the maximum adoption rate is assessed at 60%, corresponding to the measure with the highest potential adoption. From this, measures adoptions are pro-rated based on their relative independent adoption rates, to arrive at each measure's share of the 60% total adoption rate. As a result, the total adoption rate is still 60%, but it is shared by three different measures.

MEASURE INTERACTIONS - CHAINING

Chained measures are subject to adjustment when other measures are also installed in the same segment (see **Figure A- 6** below). Chaining is applied at all potential levels (technical, economic and achievable), and these interactive effects are automatically calculated according to measure screening and uptake at each potential level.

The DEEP model applies a hierarchy of measures in the chain, reducing the savings from each measure that is lower down the chain. The DEEP model adjusts the chained measures' savings for each individual measure, with the final adjustment calculated based on the likelihood that measures will be chained together (determined by their respective adoption rates), and the collective interactive effects of all measures higher in the chain.

An example is provided where insulation is added in a given segment in addition to a smart thermostat and a heat pump. **Figure A- 6** highlights the calculations used when

Figure A- 6. Example of Chaining Impact on Savings

Pre-retrofit energy use – 1,000 kWh	
Unchained	**Chained**
Insulation *Savings:* 25% x 1,000 = **250 kWh**	**Insulation** *Savings:* 25% x 1,000 = **250 kWh**
Thermostat *Savings:* 20% x 1,000 = **200 kWh**	**Thermostat** *Savings:* 20% x 750 = **150 kWh**
Heat Pump *Savings:* 30% x 1,000 = **300 kWh**	**Heat Pump** *Savings:* 30% x 600 = **180 kWh**

incorporating adoption rates to calculate chaining effects.

In the above example, the percentage of total measures adopted is calculated by taking into account the fact that some participants will adopt multiple measures. For example, for insulation alone, a 50% adoption rate is calculated when considered in isolation, and 40% is calculated for heat pumps. When chaining is considered, the adoption is distributed between those that would happen with chaining and those that happen in isolation. Therefore the assumption in this example is that 40% of the participants adopting insulation will also install a heat pump, and that 50% of the participants adopting a heat pump will also improve their insulation levels.

CUMULATIVE SAVINGS AND AGGREGATE RESULTS

To calculate the cumulative savings and report aggregate savings for each electricity system by measure, end-use, segment and sector, the following approaches are applied to roll up and adjust annual measure savings.

- **Cumulative Annual Savings**: Cumulative savings are calculated for each potential type and each year, using incremental savings potentials. Savings from individual measures are removed from the cumulative savings at the end of their effective useful life (EUL). For instance, a measure installed in Year one and with a EUL of two years would not be recounted in the cumulative potential starting in Year three.

- **Aggregate Results and Reporting**: Measure-level consumption and demand savings-related costs, and benefits are aggregated by sector, segment, end-use, measure-type, or program.

ITERATIVE QA/QC AND REFINEMENTS

To ensure that the DEEP model provides valid results for assessing the potential at all levels, a rigorous QA/QC process is applied throughout all steps in the study. This includes industry best-practices including:

- QA/QC checklists for all modelling processes
- Issue identification and trackers to ensure all items are addressed
- Data cleaning and input benchmarking to ensure all inputs
- Automated input compiling to avoid human error when loading model with study data
- Vetting with internal senior research leads, and relevant client/utility experts
- Model calibration to past program performance
- Feedback QA assessments, wherein model outputs are benchmarked to baseline sales data, and inputs are reviewed where anomalous outputs are observed
- Vetting of model with client/utility via sharing of DEEPs transparent input and calculation sheets

The DEEP model draws its inputs from a detailed measure, market, program and economic databases that are developed using jurisdiction specific data, as follows:

- **Measure Inputs:** Each measure is characterized for the specific jurisdiction being studied (i.e., all parameters are updated to reflect local climate, equipment availability and costs). Then measure costs, savings, EULs and market applicability are benchmarked against Dunsky's internal database of over 15 past potential study inputs to ensure that no values fall outside of the expected ranges, and that the inputs are adjusted or updated accordingly.
- **Market Inputs:** Detailed saturation tables are created for each measure-segment combination (referred to as markets in DEEP's modeling process). These are then benchmarked against recognized building energy thresholds (lighting densities, energy use intensities, cooling and heating capacity per unit condition floor area, average floor area per business etc.). Finally, the individual equipment saturations are benchmarked against Dunsky's internal database of equipment saturation tables, to identify any inputs that may be out of acceptable ranges or anomalous.
- **Economic Inputs:** All economic inputs are converted to real dollar terms based on the study start year, and adapted to fit the model input table formats. These are vetted internally and with the client who provided the sales projections and local economic settings to ensure consistency with internal planning values.
- **Program Inputs:** Program characterizations are developed based on a detailed study of current DSM programs in the jurisdiction, and recent evaluation reports. These are then vetted internally against our internal program characterization database and provided to utility DSM program administration representatives to ensure consistency with current program approaches, costs and incentive levels.

Once the inputs have been prepared and quality checked, a characterization database employs an automated script to assemble the input sheets and avoid any human transfer errors.

MODEL CALIBRATION

Model calibration ensures that the overall estimated energy and demand savings levels are in line with utility electricity forecasts. Because the bottom-up potential methodology is based on baseline equipment saturation data, the focus of the study calibration is on the validation of the market adoption forecast model, and to ensure that the collective inputs provide valid ranges for measure savings, costs and markets.

The study is refined using the most recent completed year of program activity available, using energy savings, demand savings, and costs. This step is more of a quick quality check on results than an actual model calibration, as there might be good reasons for the potential to be materially different from the last annual DSM results. For instance, some programs may be underperforming what is possible for such programs to achieve, or some other anomaly may impact achieved savings.

To account for these factors, calibration is performed at two levels: the overall program by program comparison, as well as at the measure level for a handful of the most influential technologies (i.e. standard LED lightbulb counts in the residential sector) that are typically not impacted by differences in program scope or program underperformance.

The calibration exercise identifies the extent to which the assessment of adoption rates – based on a combination of economic drivers and assumed market barrier levels – appears consistent with recent achievements. Large discrepancies are then reviewed and classified with one (or a combination) of four findings:

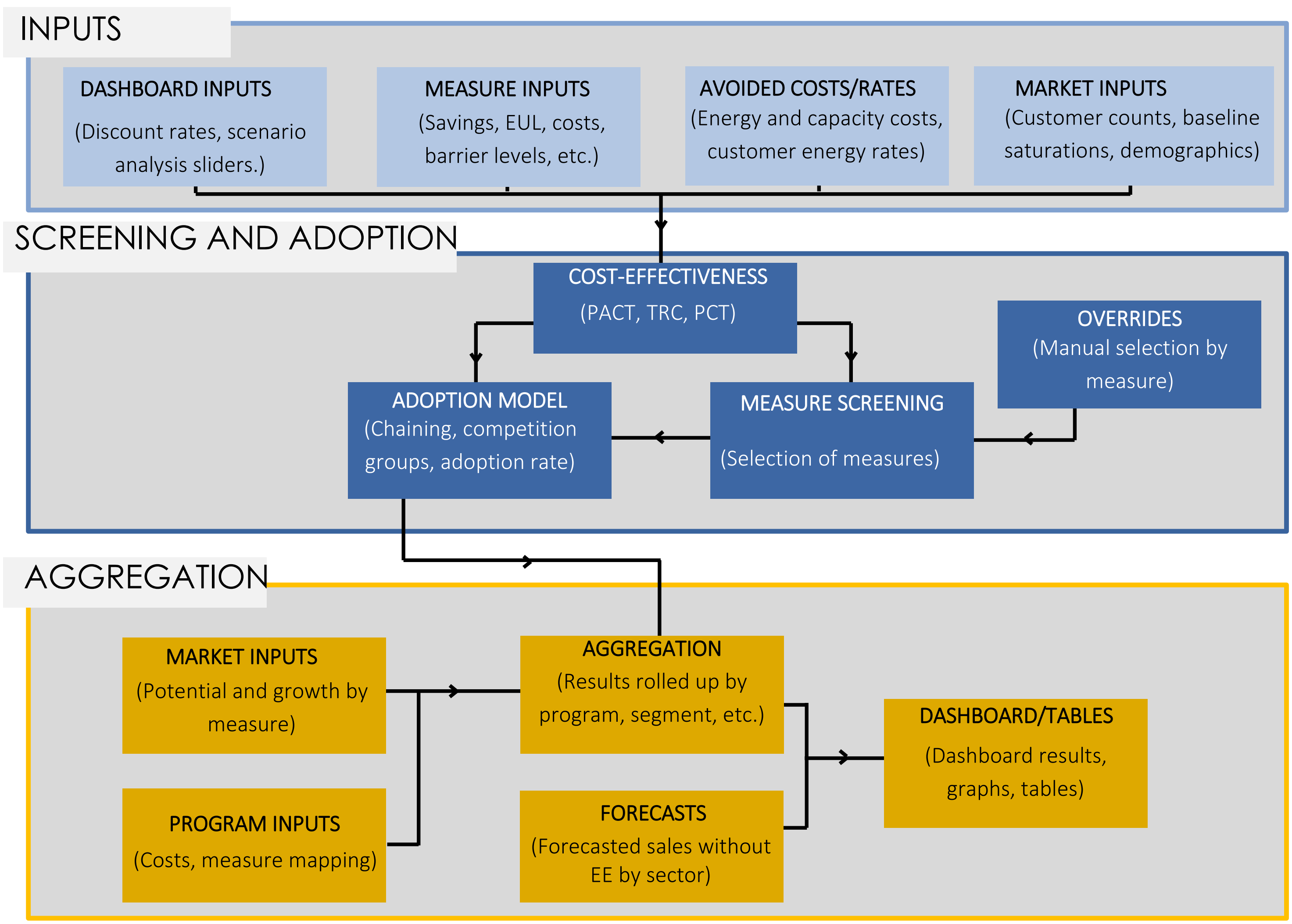
(1) The model is consistent with expected results;
(2) The market adoption algorithm needs to be revisited;
(3) Barrier levels for market adoption need to be revisited; or
(4) An anomaly likely explains an inconsistency, so no change is required.

These findings then inform iterative adjustments to the model inputs and settings before draft and final results are generated and shared with the client and/or stakeholders.

MODEL ARCHITECTURE

Figure A- 7 below presents an overview of the DEEP model's computational structure, including inputs, calculations, and aggregation. The methodology uses a bottom-up approach, beginning at the measure level with individual measure characterization (the top-most row in **Figure A- 7**). The measures are then screened and adoption rates are calculated based on cost-effectiveness results (middle row below). Measure results are then rolled-up by program, segment, sector, energy source, and end use for each electricity system.

Figure A- 7. DEEP model structure



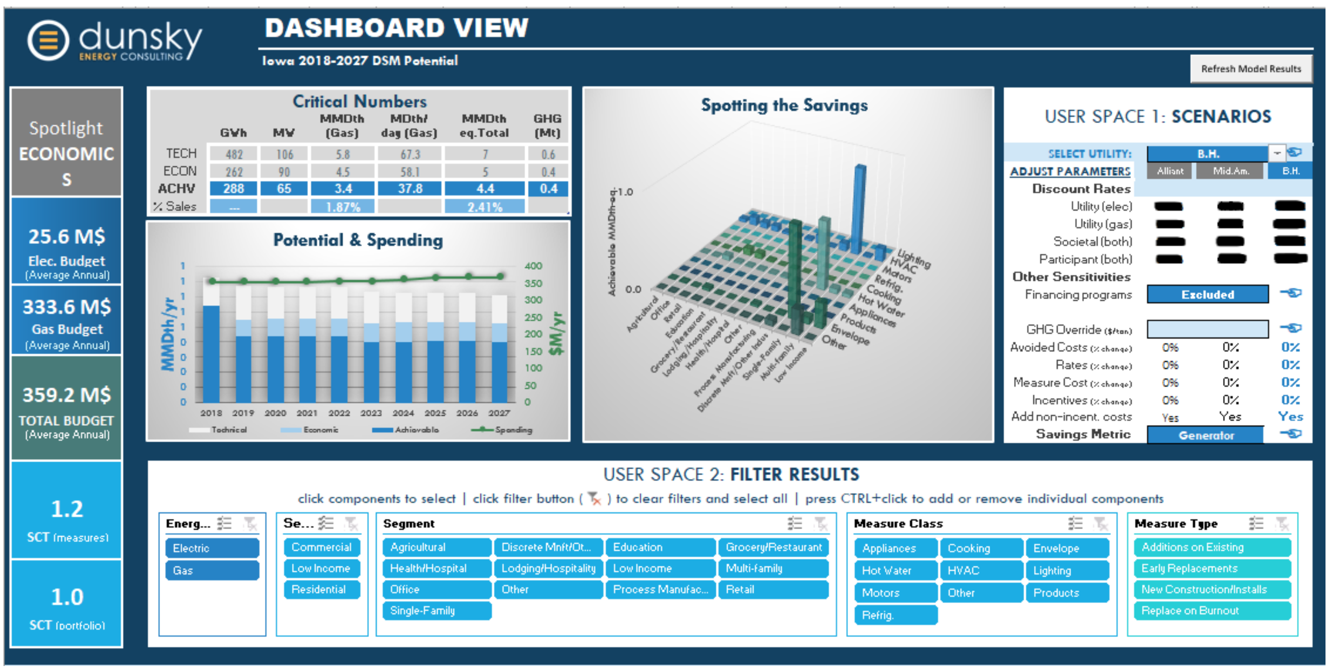
SCENARIO ANALYSIS DASHBOARD

The DEEP model can be delivered for use by the Utilities to run further what-if scenarios. To facilitate this, DEEP is equipped with a dashboard that provides a summary of the model outputs (results), and a range of user-input fields to adjust the model settings to test further scenarios. The model comes equipped with all input data and can be run on a PC equipped with MS Excel 2013 or later.

The Utilities also have access to measure and program input and output tables. Core input assumptions in the model are clearly defined and can be easily changed to conduct sensitivity analysis for efficiency measures, and adjust to changing market conditions (e.g. energy prices, economic growth) as well as recent program and evaluation results.

Figure A- 8 below shows a snapshot of the DEEP dashboard, which is the main entry point to use the model's features, run sensitivity analyses, and get high-level results.

Figure A- 8. DEEP Model – Dashboard View



APPENDIX B: DEMAND RESPONSE POTENTIAL METHODOLOGY

Dunsky's approach to analyzing demand response (DR) potential takes into account two specific considerations that differentiate it from energy efficiency potential assessments.

DR Potential is Time-Sensitive

- DR measures are often subject to constraints based on when the affected demand can be reduced and for how long.
- DR measure "bounce-back" effects (caused by shifting loads to another time) can be significant, creating new peaks that limit the achievable potential.
- DR measures impact one another by modifying the System Load Shape – thus the entire pool of measures (at all sites) must be assessed together to capture these interactive effects and provide a true estimate of the achievable potential impact on the system peak.

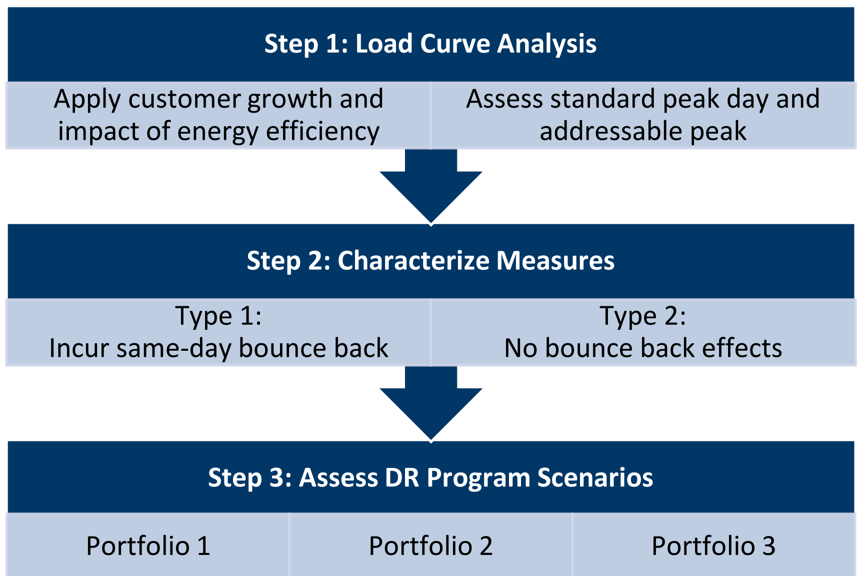
Many DR Measures Offer Little or no Direct Economic Benefits to Customers

- Participants must receive an incentive over and above simply covering the incremental cost associated with installing the DR equipment.
- Incentives can be based on an annual payment basis, a rebate/reduced rate based on a participant agreement to curtail load, or through time-dependent rates that send a price signal encouraging load reduction during anticipated system peak hours.
- Savings are expected to persist only as long as programs remain active.

The following sections outline Dunsky's Demand Response Model methodology, used to assess the technical, economic and achievable peak demand savings from electric demand response programs.

Figure B- 1 presents an overview of the analysis steps applied to assess the DR potential in this study. For each step, system-specific inputs are identified and incorporated into the model. Each step is described below.

Figure B- 1: Demand Response Potential Assessment Steps



STEP 1: LOAD CURVE ANALYSIS

The first modelling step of Dunsky's approach is to define the baseline load forecast and determine the key parameters of the utility load curve that influence the DR potential. The process begins by conducting a statistical analysis of historical utility data to determine the 24-hour load curve for the "Standard Peak Day" against which DR measure impacts are assessed. The utility peak demand forecast period is then applied to adjust the amplitude of the standard peak day curve over the study period. Finally, relative market sector growth factors and efficiency program savings are applied by end-use to further adjust the shape and amplitude of the peak day load curve.

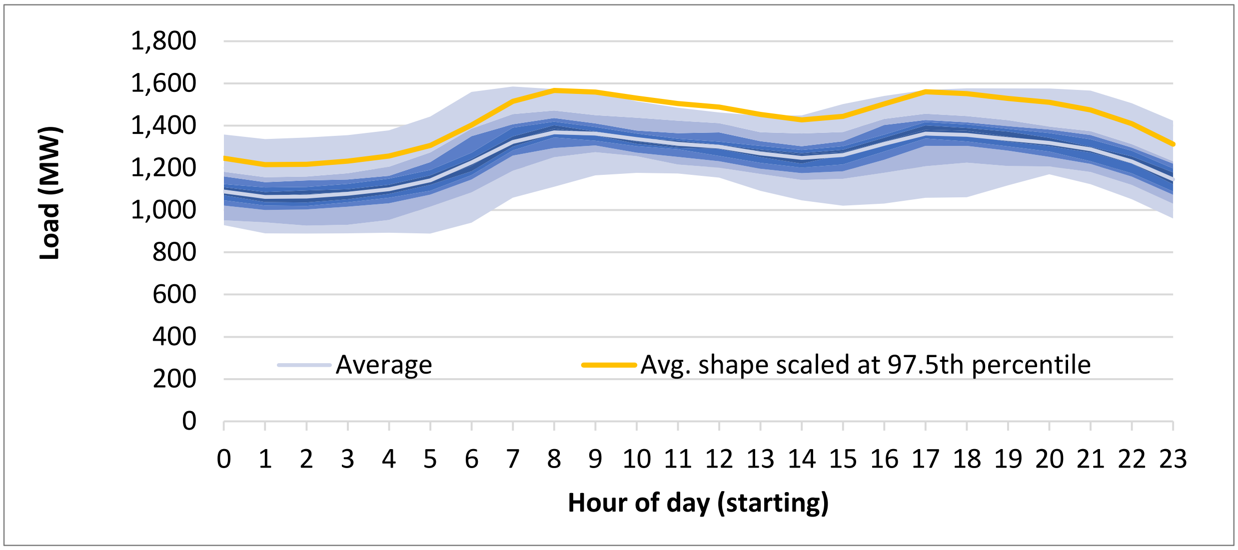
Figure B- 2: Load curve analysis tasks

Once complete, the load curve analysis provides a tool which can assess the individual measure, and combined program impacts against a valid utility peak baseline curve that evolves to reflect market changes over the study period.

IDENTIFY STANDARD PEAK DAY

The **Standard Peak Day** is assessed through an analysis of historical hourly annual load curves. For each year, a sample of the peak days are identified (e.g. 10 top peak demand days in a given year) and a pool of peak days is established. Each peak is normalized in order to compare the shape peaks. From this the average peak day shape is assessed by averaging the hourly shape. The standard peak day load curve is then defined by raising the average peak day load curve such that the peak moment matches the peak demand on the 97.5th percentile peak day (keeping the shape consistent with the average curve), as shown in **Figure B- 3** below.

Figure B- 3: Standard Peak Day Selection Curve (IIC)



Note: each blue shading area represents a 10 percentile gradient.

From the standard peak day curve, two DR windows were identified which represent the 3-5 hour time periods that capture the highest demand hours. These are assessed against the historical annual curves to ensure that 90% of DR peak events within a given year fall within the defined DR windows. These are used to characterize certain DR measures, providing guidance on which hours to target for high time of use (TOU) rate tiers, customer driven curtailment periods, and to create pre-charge/reduction/re-charge curves for equipment control measures, as described in the next step.

STEP 2: CHARACTERIZE DR MEASURES

DR potential is assessed drawing on Dunsky's database of over 30 specific demand reducing measures developed from a review of commonly applied approaches in DR programs across North America, and emerging opportunities such as battery storage.[4] Measures are characterized with respect to the local customer load profiles, and the technical and economic potentials are assessed for each measure.

Figure B- 4: DR Measure Characterization Tasks

Once complete, the measure-specific economic potential is assessed, and loaded into the model to assess the achievable potential scenarios when all interactive load curve effects are considered.

MEASURE SPECIFIC MODEL INPUTS

Measures are developed covering all customer segments and end-uses, and can be broadly categorized into two groups:

- **Type 1 DR Measures (typically constrained by demand bounce-back and/or pre-charging):**
  - These measures exhibit notable pre-charging or bounce-back demand profiles within the same day as the DR event is called. This can create new peaks outside of the DR window and may lead to significant interaction effects among measures, when assessed within their combined impact on the utility peak day curve.
  - Typically, Type 1 measures can only be engaged for a limited number of hours before causing participant discomfort or inconvenience. This is reflected in the DR measure load curves developed for each measure-segment combination.

[4] A detailed list of measures applied in this study is provided in Appendix E.

- **Type 2 DR Measures (unconstrained by load curve):**
  - These measures do not exhibit a demand bounce-back and are therefore not constrained by the addressable peak.
  - Some of them can be engaged at any time, for an unlimited duration.
  - These measures tend to not have interactive effects with other measures.

Dunsky's existing library of applicable DR measure characterizations is applied and adjusted to reflect hourly end-use energy profiles for each applicable segment. Key metrics of the characterization are:

1. **Load Shape:** Each measure characterization relies on an estimate of the 24-hour load shape both before and after the demand response event. The load shapes are based on the population of measures within each market segment and are defined as the average aggregate load in each hour across the segment.

2. **Effective Useful Life (EUL):** Effective useful life of the installed equipment/control device. For behavioural measures with no equipment, a one-year EUL is applied.

3. **Costs**: At measure level, the costs include the initial cost of the upgrade and the annual operational cost (costs of AMI installation or program not included).

4. **Constraints:** Some measures are subject to specific constraints such as the number of hours per day or year, maximum number of events per year and event durations.

Once the measures are adapted to the utility customer load profiles and markets, the technical and economic potentials are assessed for each measure independently as outlined below. Because these are assessed independently, the technical and economic potentials are not considered to be additive, but instead provide important measure characterization inputs to assess the collective achievable potential when analyzed together in step 3.

TECHNICAL POTENTIAL (MEASURE SPECIFIC)

The technical potential represents a theoretical assessment of the total universe of controllable loads that could be applicable to a DR program. It is defined as the technically feasible load (kW) impact for each DR measure considering the impact on the controlled equipment power draw coincident with the utility annual peak.

More specifically, the technical potential is calculated from the maximum hourly load impact during a DR event multiplied by the applicable market of the given measure. It is important to note that the technical potential assessment does not consider the utility load curve constraints.

ECONOMIC POTENTIAL (MEASURE SPECIFIC)

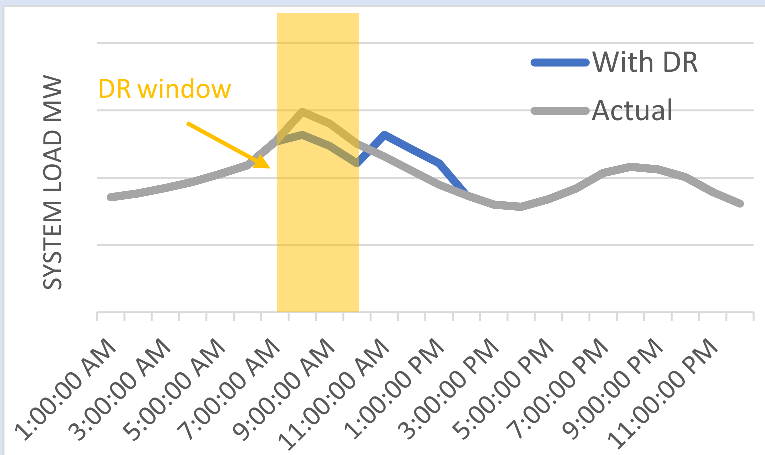
The assessment of each measure's economic potential is conducted in three key steps: adjustment of the technical potential, screening for cost-effectiveness, and adjusting for market adoption limitations.

1. **Technical Potential Adjustment:** The measure's hourly load curve impact is applied to the utility standard peak day load curve, to assess the net impact after pre-charge and bounce-back effects are accounted for. For each individual measure an optimization algorithm that assesses various control schemes and market portions is applied to arrive at the maximum number of participants and impact for the given measure, without creating a new system peak, either during the standard peak day, or over the sample annual hourly load profile.

Load Curve Impact Optimization Example:

By considering the bounce-back effect associated with water heaters recharging their reservoirs after the evening DR window has passed, **Figure B- 5** illustrates how adding too many water heaters to the DR program would risk creating a new peak outside of the DR window. This new peak is used to assess the net impact of the measures, which is determined as the difference between the peak before the DHW controls were applied and the new peak after the DHW controls were applied.

Figure B- 5: Illustrative Domestic Hot Water (DHW) Bounce-Back Effect Example



2. **Cost-Effectiveness Screening:** Once each measure's individual impact on the peak is assessed, it is then screened for cost-effectiveness, retaining just the measures with a PACT > 1 when considering installation costs and baseline incentive costs.[5] The PACT is considered the most appropriate existing test 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

[5] Any measure that cannot achieve a PACT > 1.0 is not retained for further consideration in the model. For customer curtailment measures PACT screening may be assessed under a baseline incentive level (i.e. $20/kW). For equipment control measures the baseline incentive can be set to zero, and then adjusted for measures that return net benefits to the utility.

equipment costs (unlike in efficiency programs where the incentives provided cover a portion of the participant's incremental costs for the efficiency upgrade).

Table B- 1: DR Benefits and Costs Included in Determination of the PACT

Benefits	Costs
• Avoided Capacity Costs • Other ancillary benefits (as applicable)	• Controls equipment installation • Controls equipment Operations and Maintenance (O&M) (if required) • Annual incentives ($/ participant) • Peak reduction incentives ($/kW contracted)

For measures that pass the PACT screening, program incentives can then be set either as a fixed portion of the avoided costs benefits net of measure costs (i.e. 50%) or at the level that maximizes the PACT value for each measure that passes the cost-effectiveness screen.

3. **Market Adoption Adjustment**: The market for a given DR program or measure may be constrained either by the impact on the load curve, or by the expected participation (or adoption) among utility customers.

   In the first case, the economic potential assessment (described above) determines the number of devices needed to achieve the measure's maximum impact on the utility peak load. Adding any further participation will come at a cost to the utility, but with little or no DR impact benefits.

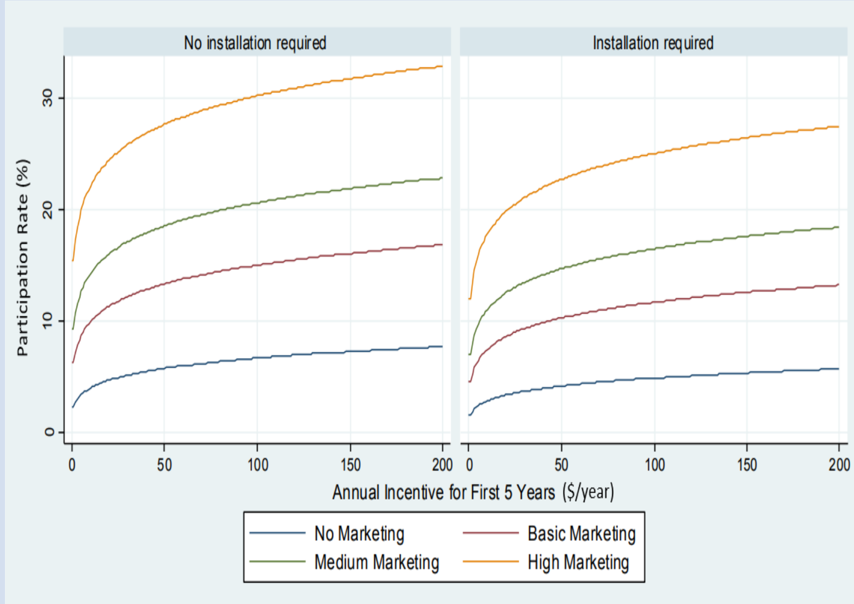
   In the second case, the model determines the expected maximum program participation based on the incentive offered, the need to install controls equipment, the level of marketing, and the total number of eligible customers, by applying DR program propensity curves (described in the call out box below) developed by the Lawrence Berkeley National Laboratory.[6]

[6] Lawrence Berkeley National Laboratory, March 2017. 2025 California Demand Study Potential Study, Phase 2 Appendix F. Retrieved at: http://www.cpuc.ca.gov/General.aspx?id=10622

Demand Response Propensity Curves

For each measure the propensity curve methodology, as developed by the Lawrence Berkeley National Laboratory to assess market adoption under various program conditions, is applied. The curves represent achievable enrollment rates as a function of incentive levels, marketing strategy, number of DR calls per year, and the need for controls equipment. Their development is based on empirical studies, calibrated to actual enrollment from utility customer data. Specific curves are available for each sector.

Figure B- 6: Residential Adoption Curves used in the study



The DR model assesses both the utility curve economic potential market and the maximum adoption at the resulting incentive levels, then constrains the market (maximum number of participants) to the lower of the two. This is then applied as a measure input for the achievable potential assessment described in the next step.

STEP 3: ASSESSMENT OF ACHIEVABLE POTENTIAL SCENARIOS

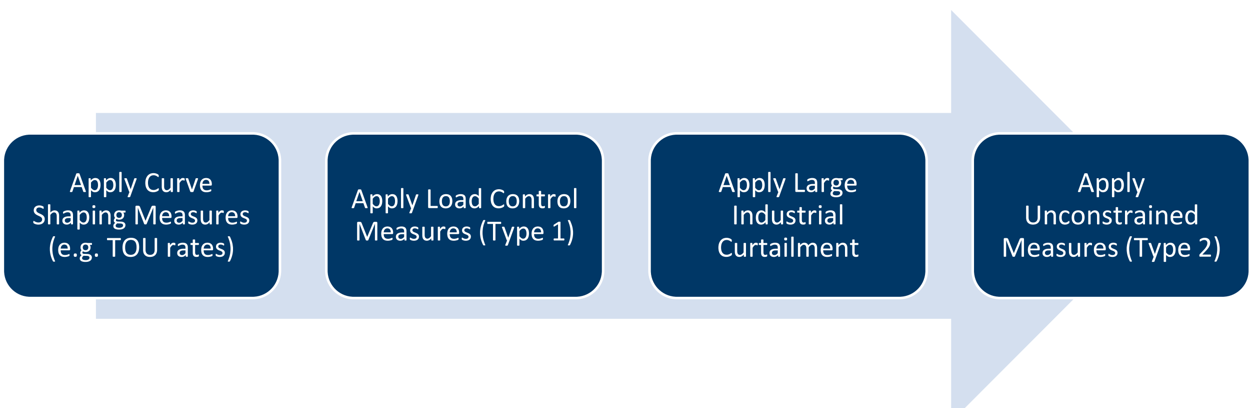
The achievable potential is based on the calibration of each measure's potential using an optimization process that considers market adoption constraints, individual measure constraints, and the combined inter-measure impacts on the utility load curve.

Scenarios are developed to assess the combined impact of selected programs and measures. For example, one scenario may assess the achievable potential of the impact of applying TOU rates and industrial curtailment, while another may assess the combined potential from direct load control of customer equipment and industrial curtailment. This approach recognizes that there can be various approaches to access the demand reduction potentials from the same pool of equipment (i.e. TOU rates can exert a reduction in residential water heating peak demand, thereby reducing or eliminating the potential from a water heater DLC program). The scenarios are assembled from logical combinations of programs and measures designed to test various strategies to maximize the achievable peak load reduction.

ASSESSING ACHIEVABLE POTENTIAL

For each scenario, measures are applied in groups in order starting with the least flexible/most constrained measures and progressing to the measures/groups that are less and less constrained, as per the order illustrated in **Figure B- 7** below.

Figure B- 7: Achievable Potential Assessment Tasks



- **Curve Shaping:** Rates Based Measures (such as time of use rates) are typically applied first as these are designed to alter customer behaviour with time, and are considered the least flexible (i.e. with the exception of critical peak pricing, they cannot be engaged by the utility to respond to a specific DR event, but must be set in place and exert a prolonged effect on the utility load curve shape).
- **Type 1 Load Control Measures:** Direct control of connected loads such as water heaters and thermostats, and customer controlled shut-off or ramp down of commercial HVAC loads are

applied next. These are typically constrained to specific times of day based on the utility peak load shape, and the controlled equipment load shape (i.e. turning of residential water heaters at midday may be feasible but deliver next to no savings as there is minimal hot water demand at that hour). These are assessed against the load curve altered by any shaping measures, and measures that may double count savings are eliminated. A new aggregate utility load curve is then created, applying the achievable load control peak reductions, and bounce-back effect.

- **Industrial / Commercial Curtailment:** Next customer curtailment is applied, which typically carries constraints related to the number of curtailment hours per day (consecutive and total), the number of events per year, and in some cases the time of day that curtailment can be applied. These are applied to the adjusted load curve, after direct load control impacts have been applied, to assess if the changes how the adjusted utility load curve impacts the potential impact of large industrial curtailment measures.
- **Unconstrained Measures:** Finally, the remaining Type 2 measures that have no constraints on the duration, frequency or timing of their application are applied. These may include measures such as dual-fuel heating, back-up generators, and conservation voltage regulation, which can be engaged as needed and whose potential is not impacted by the shape of the utility load curve.

DR PROGRAMS AND SCENARIOS

A set of best-in-class program archetypes is defined in the model based on a review of programs in other jurisdictions and information regarding the current programs in the province. For each program, development, marketing and operating costs have been estimated and applicable measures have been mapped to the corresponding program.

The model first determines the achievable peak demands of the combined measures within all programs, and then assesses the program level cost-effectiveness, combining appropriate measures within a given program, summing all program and measure costs, as well as applicable measure benefits. A minimum 10-year period is assumed for each program, except where the program is based on control devices with a longer EUL, in which case the program is assumed to cover the entire device life. In cases where DR device EULs are shorter than 10 years, re-installation costs are applied.

New measure and program ramp-up: Where applicable, new programs and measures can be ramped up accounting for the time needed to enroll customers and install controls equipment to reach the full achievable potentials. Ramp up trajectories applied to the achievable potential markets after all interactive effects (i.e. new peaks created or program interactions that affect the net impact of any other program) have been assessed.

Program Costs: Table B- 2 below presents the program costs for each major program type applied in the DR potential model. Program costs account for program development (set up), annual management costs, and customer engagement costs. These are added over and above any equipment installation and customer incentive costs to assess the overall program cost-effectiveness. In some cases, a program's constituent measures may be cost-effective, but the program may not pass cost-effectiveness testing due to the additional program costs. Under those scenarios, the measures in the underperforming program are eliminated from the achievable potential measure mix, and the DR potential steps are recalculated to reassess the potential and cost-effectiveness of each measure and program.

Table B- 2: DR Program Administration Costs Applied in Study (excluding DR equipment costs)

Program	Development Complexity	Admin Complexity	Development Costs	Program Fixed Annual Costs (1 FTE = 75,000)	Other Costs ($/customer) for marketing, IT, admin
Residential DLC	Small/Medium	High	$100,000	$75,000	$12
DR Backup Power	Medium	Med	$150,000	$75,000	$1,200
DR Commercial	Medium	Med	$150,000	$75,000	$1,200
Large Industrial Curtailment	Medium	Med	$150,000	$75,000	$3,500
TOU - Residential	Larger (billing system adjustments)	Med	$300,000[7]	$75,000	$90[8]
TOU - Commercial	Larger (billing system adjustments)	Med	$300,000	$75,000	$90
Smart Electric Vehicle Supply Equipment	Medium	Med	$150,000	$75,000	$5

[7] Development costs do not include AMIs. As stated in Appendix E, the costs of a full deployment of AMIs is estimated to be $85M– $105M.

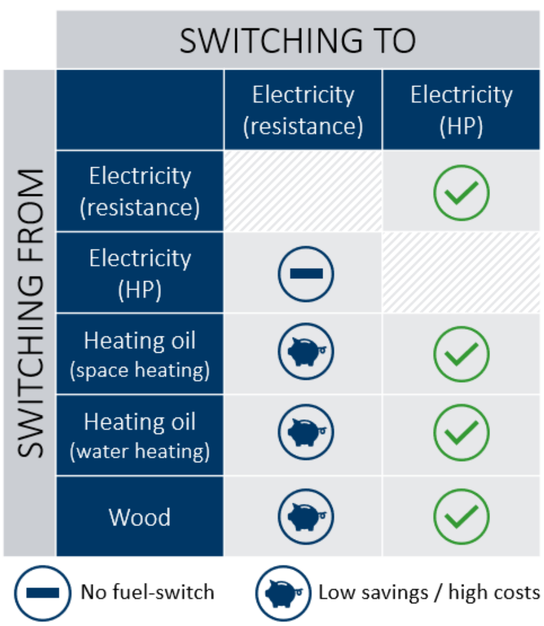
[8] Costs taken from “Decision – Matter No.375”, New Brunswick Energy and Utilities Board, 2018

APPENDIX C: FUEL SWITCHING STUDY METHODOLOGY

The fuel switching analysis assesses how many households and businesses can be expected to replace oil- and wood-fueled space and hot water heating systems with electric heat pumps over the study period under various incentive scenarios. It only considers customers within the Newfoundland Island Interconnected System (IIC).[9]

The analysis focuses on switching from combustible fuel to electricity to estimate the potential to displace heating fuels in favour of electricity consumption. The adoption of fuel switching measures is based on customer economics and barriers, using the same adoption modeling approach described in the DEEP model (see Appendix A). For residential customers, adoption is driven by the simple payback period, which does not discount future costs and savings, while for commercial customers, adoption is driven by the participant cost test (PCT) to account for more sophisticated purchasing practices.

Figure C- 1: Summary of Fuel Switching Combination Screening



Fuel switching measures were identified by comparing retail rates for the available sources of energy and adjusting the number of opportunities for each measure to reflect feasible fuel switching configurations based on cost and complexity. Ultimately, the analysis considered switching from oil and wood-based systems to electric heat pump systems. Switching to electric-resistance systems was excluded due to generally low (or negative) cost savings and/or high installation costs. In order to calibrate findings to overall heat pump market adoption trends an assessment for adding ductless mini-split heat pumps in households with electric resistance baseboards was included.

[9] Labrador Interconnected and Isolated-Diesel Systems are excluded due to limited fuel switching opportunities.

MEASURE CHARACTERIZATION

The identification of specific fuel switch combinations was based on an assessment of the NL market and Residential End Use Survey (REUS)/Commercial End Use Survey (CEUS) results. Full and partial fuel switching options were considered. Measures were characterized for viable fuel switch combinations. Measure characterizations are primarily based on modified algorithms and measure assumptions from published Technical Reference Manuals (TRMs) and supplemented with other sources (e.g. RSMeans data[10], market actor interviews). Measure characterizations include the following parameters:

- Energy and peak demand impacts, costs, effective useful life, etc.
- Marginal retail electricity rates and heating fuel costs (oil and wood)
- Market characterization results (CEUS and REUS)

Air source and ductless mini-split heat pumps are assumed to have efficiencies equivalent to the 2023 federal standard throughout the study period. Baseline oil and wood-fueled technologies are assumed to meet, but not exceed, federal efficiency standards.

The residential and commercial fuel switch measures characterized in this study are listed in **Figure C- 2** and **Figure C- 3** below, respectively.

[10] RSMeans is a database of construction costs including equipment, material and labor costs developed and maintained by Gordian. See: www.rsmeans.com

Figure C- 2: Summary of Fuel Switching by Technology (Residential)

RESIDENTIAL			
SWITCHING FROM	**SWITCHING TO**	**COMMENTS**	**TRM SOURCE**
Oil furnace	Central ducted air source heat pump		Massachusetts Technical Reference Manual (October 2018), 1.4 Air Source Central Heat Pump.
Oil furnace	Ductless mini-split heat pump	Partial switch	Massachusetts Technical Reference Manual (October 2018), 1.25 Ductless Mini-Split Heat Pump.
Oil boiler	Air to water heat pump		Modified from Massachusetts Technical Reference Manual (October 2018), 1.4 Air Source Central Heat Pump.
Oil boiler	Ductless mini-split heat pump	Partial switch	Massachusetts Technical Reference Manual (October 2018), 1.25 Ductless Mini-Split Heat Pump.
Wood furnace	Central ducted air source heat pump		Massachusetts Technical Reference Manual (October 2018), 1.4 Air Source Central Heat Pump.
Wood furnace	Ductless mini-split heat pump	Partial switch	Massachusetts Technical Reference Manual (October 2018), 1.25 Ductless Mini-Split Heat Pump.
Oil hot water heater	Heat pump hot water heater		New York Standard Approach for Estimating Energy Savings from Energy Efficiency Programs – Version 7, Domestic Hot Water, Heat Pump Water Heater (HPWH).

Figure C- 3: Summary of Fuel Switching by Technology (Commercial)

COMMERCIAL			
SWITCHING FROM	**SWITCHING TO**	**COMMENTS**	**TRM SOURCE**
Oil furnace	Central ducted air source heat pump		Mid-Atlantic Technical Reference Manual - Version 8, Unitary HVAC Systems.
Oil furnace	Ductless mini-split heat pump	Partial switch	Mid-Atlantic Technical Reference Manual - Version 8, Ductless Mini-Split Heat Pump.
Oil boiler	Air to water heat pump		Modified from Mid-Atlantic Technical Reference Manual - Version 8, Unitary HVAC Systems.
Oil boiler	Ductless mini-split heat pump	Partial switch	Mid-Atlantic Technical Reference Manual - Version 8, Ductless Mini-Split Heat Pump.
Oil hot water heater	Heat pump hot water heater		Pennsylvania Technical Reference Manual (June 2015), 3.4.2 Heat Pump Water Heaters.

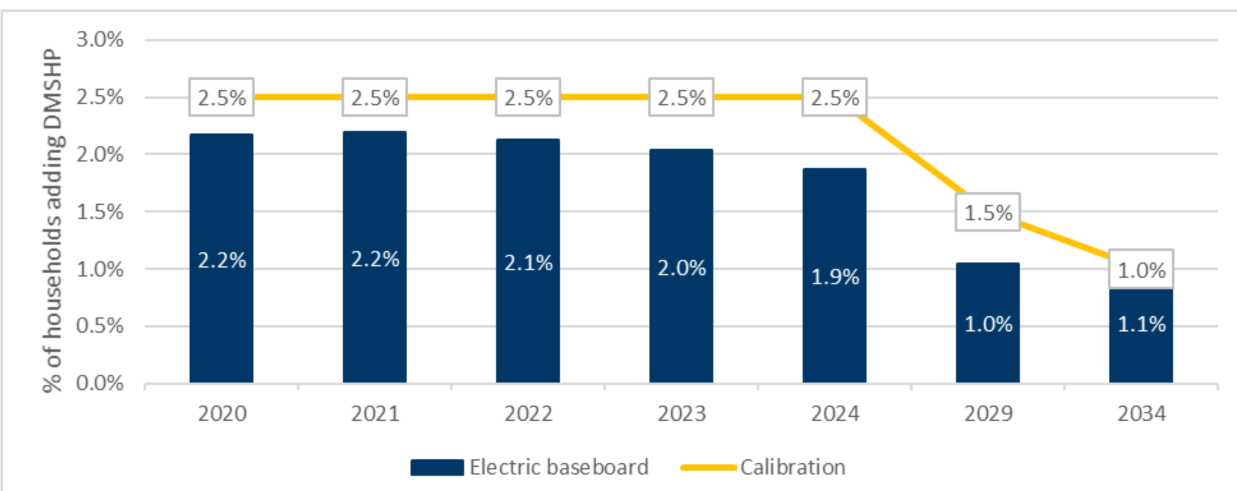
FUEL SWITCHING MODELING

The annual uptake of each fuel switch combination in each year of the study period is modeled and compared to various scenarios considering the impact that incentives and programs can have on the magnitude of fuel switching rates in each market segment. The model produces the following results:

- Annual uptake (number of customers per year)
- Impact on annual electricity sales and annual peak load
- Costs and benefits to customers and utilities
- Net greenhouse gas impacts (based on displacing oil consumption in favour of electricity)

The model was calibrated based on residential heat pump growth factors derived from end-use surveys and the 2018 takeCHARGE Market Study. Based on this information, market adoption of ductless mini-split heat pumps is assumed to be an additional 2.5% of all households annually between 2020 and 2024. This adoption will almost entirely occur among households with electric baseboard heating systems. After 2024, adoption tapers off with 1.5% of households adopting annually between 2025 and 2029 and 1% adoption between 2030 and 2034. The model is calibrated to these assumptions under a scenario with no utility incentives but with HIGH electricity rates to simulate consumer anticipation for higher electricity costs in the future. Ultimately, the model predicts adoption rates similar, but slightly below (roughly 16% below), our baseline adoption assumptions for households with electric baseboard heating. This discrepancy is likely a result of uncertainty over current baseline heat pump adoption, that was determined over just a single 2-year period (the REUS in 2017 and a residential market study conducted in 2018). The results indicate that the assumed baseline heat pump adoption may have been somewhat overestimated, and could possibly decline as the market becomes increasingly saturated. The model found little to no adoption among oil- and wood-heated households, which is aligned with assumptions.

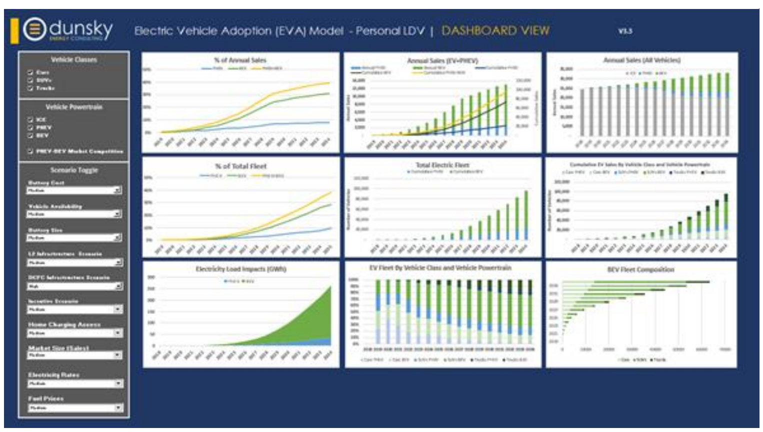
Figure C- 4. Model calibration results: residential adoption of DMSHP



APPENDIX EVA D: ELECTRIC VEHICLE ADOPTION (EVA) MODELING METHODOLOGY

The analysis of Electric Vehicles (EV) leverages Dunsky's Electric Vehicle Adoption (EVA) Model to project EV uptake in Newfoundland Labrador (NL) over the study period. Dunsky's EVA Model was developed in-house to address a growing need by its clients to understand the potential size of the electric vehicle market in their respective jurisdictions and corresponding utility impacts. Based on rigorous review of research from academia and industry, EVA leverages the modeling framework behind Dunsky's Solar Adoption Model (SAM) and builds on the knowledge base and expertise from the company's work with EV modelling.

Figure D - 1. Dashboard View



In addition to providing jurisdiction-specific forecasts for EV adoption, EVA can be used to assess the effectiveness of a range of policy and program options for accelerating EV adoption as well as the sensitivity of EV uptake to key market and technology uncertainties such as battery costs. Results from EVA are then used to assess the impact of the electrical load growth associated with an increasingly electrified transportation sector, helping utilities to plan ahead for this transition and put solutions into place that can help to manage this load growth in the most effective way.

MODEL METHODOLOGY

The model segments the vehicle market into:

- **Vehicle classes:** which are segments of vehicles that share similar characteristics and utilization profiles. For example, cars, SUV, truck, medium-duty, heavy-duty, and buses
- **Vehicle powertrains:** Including Battery Electric Vehicle (BEV), Plug-in Hybrid Electric Vehicle (PHEV), and Internal Combustion Engine (ICE)

EVA model projects market adoption of EVs of each vehicle class within a defined jurisdiction based on several key factors:

- **Technical potential:** The model assumes that annual vehicle sales represent the theoretical potential for EV deployment (i.e. 100% market share). A key consideration in assessing the technical potential is the availability of EV powertrains for the modeled segment. For each vehicle class, the availability of different powertrain types (e.g. plug-in hybrid, battery electric) is assigned a qualitative availability metric (None, Low, Medium or High) based on current availability of models in the market as well as estimated future availability based on industry projections or automakers' announcements; where None indicates no EV choices are available, and High indicates a similar number of EV choices as ICE.

- **Customer economics:** For each vehicle class and powertrain, the model uses key inputs to calculate a bottom-up vehicle cost based on vehicle characteristics (powertrain size, battery size, etc.). Additionally, Total Cost of Ownership (TCO) of each vehicle is calculated using an assumed lifetime and driving distance and considering fuel and operations and maintenance (O&M) costs over the vehicle's lifetime. The incremental upfront cost and Total Cost of Ownership (TCO) of EVs over ICE vehicles are then computed and used to estimate the unconstrained economic potential (i.e. the portion of the market that will opt for EVs at a certain price threshold not considering any other barriers) based on economic adoption curves embedded within the model. These curves are based on consumer willingness-to-pay from consumer choice research and surveys. Consumers in the personal LDV segment are assumed to consider both upfront cost and TCO in their decision-making, whereas commercial consumers are assumed to consider the vehicle's TCO and associated Internal Rate of Return (IRR).

- **Constrained potential:** EVs face several specific barriers that constrain their wide-spread adoption. EVA uses barrier curves along with jurisdiction-specific inputs to assess the impact on key barriers adoption locally. These barrier curves highlight the relationship between metrics that depict the level of each barrier and the portion of the market that is estimated to be willing to adopt EVs at given barrier level. The following barriers are considered within the model:

    - **Range requirement:** A portion of the market is constrained by the limited range of EVs. This barrier is only assumed to affect BEVs and not PHEVs, due to their ability to use ICE powertrain to complement electric driving range.

- **Home charging access:** Research indicates that the majority of EV charging is expected to happen at home overnight (or in depots for commercial fleets), therefore access to home charging is considered key for enabling EV adoption. While single-family homes often have dedicated parking, residents in Multi-Unit Residential Buildings (MURBs) usually do not. The model uses data on local housing composition (i.e. percentage of population living in single-family homes versus multi-family homes) and assumes the portion of each segment that has dedicated parking. The barrier level can be reduced over time through building code changes that require parking stalls to have EV charging station or incentives and programs to increase home charging access. Additionally, a portion of "garage-orphans"[11] are assumed to consider EVs even given their lack of access to dedicated parking stalls.

- **Public Charging:** Public charging can be a key enabler or barrier of EV adoption. The model captures two specific characteristics of local charging networks:[12]

  - **Coverage**: The geographical coverage of charging infrastructure considering the required number of stations regionally. Inputs on population, land area, highway length and other regional data are used to determine the required number of DCFC charging stations on highway corridors and in population clusters.

  - **Availability:** An assessment of the number of EVs per port for both Level 2 and DCFC charging stations. The calculated ratios are compared to estimated "ideal ratios". These ideal ratios are dynamic and are recalculated every time-step (i.e. year) based on population density (population per km^2), EV density (EVs per km^2), average year-round temperature, and home charging access.[13] In addition to the number of ports, availability also considers the average charging time given the capacity (kW) of the deployed charging stations and the corresponding charging time for each vehicle.

- **Market dynamics:** Incorporating technology diffusion theory and other market factors to determine rate of adoption and competition between vehicle types.

  - **Competition**: PHEVs and BEVs are assumed to be in competition for the same market. After comparing technical, economic, constrained and market potential of both technologies, a

---

[11] Garage orphans is a term used to describe residents that do not have access to dedicated off-street garage or parking.

[12] EVA uses the following terminology for charging infrastructure. A **charging station** is assumed to be a facility or location that provides charging services, and can provide charging to one or more EVs at a time depending on the number of ports it includes, whereas a **charging port** is used to refer to a connector that can charge one vehicle at a time. (Note that some "dual port" stations include connectors for different vehicle types, but can only charge one vehicle at a time – considered as a single port in EVA).

[13] The model assumes that the portion of EV drivers who do not have access to home charging impacts the need for public charging (i.e. if EV adopters do not have home charging, they will have a higher reliance on public charging and therefore more charging ports will be required).

probabilistic function is used to represent the portion of the market that will be rational decision-makers and select the superior of the two options (i.e., – the choice that minimizes overall barriers), versus a portion that will adopt the inferior of the two options.

- **Diffusion:** Technology diffusion theory is used to estimate the rate of adoption of EVs. Specifically, the Bass Diffusion curve is used to capture the degree to which the market adopts new innovative technologies over time. This accounts for the demographics and composition of the market through segmenting potential adopters into five categories that vary by motivation for adoption (environmental, economic, etc.), willingness to take risks, technology-savviness, and other factors. The diffusion curve accounts for social interactions and public awareness (or lack of) and the impact of programs on increasing this awareness. Key parameters of the diffusion curve are adjusted to capture the local market characteristics by calibrating the model to historical uptake.

By overlaying the technical potential, customer economics, constrained potential, and market dynamics, EVA is used to model the market share of EVs in the specific segment.

While the treatment of the various vehicle segments is largely the same in EVA, there are a number of differences in in the model's consideration of barriers facing personal LDV, commercial LDV, and commercial MDV/HDV/Bus segments, highlighted in **Table D- 1**.

Table D- 1: Model Treatment of Vehicle Segments, with Differences between Segments in Bold

Barrier	Personal LDV	Commercial LDV	Commercial MDV/HDV/Bus
Technical	Base vehicle assumed to be **gasoline ICE**		Base vehicle assumed to be **diesel ICE**
Economic	**Upfront cost and Total Cost of Ownership (TCO)**	**Internal Rate of Return (IRR)** of the vehicle's upfront and operational costs over its lifetime	
Constraints	• Range Requirement • Charging Time • Public Charging Coverage • **Home Charging Access** • **Public Charging Availability**	• Range Requirement • Charging Time Requirement • Public Charging Coverage	• Range Requirement • Charging Time Requirement
Market	Competition between PHEV and BEVs		**No competition between PHEVs and BEVs (i.e. all assumed to be BEVs)**

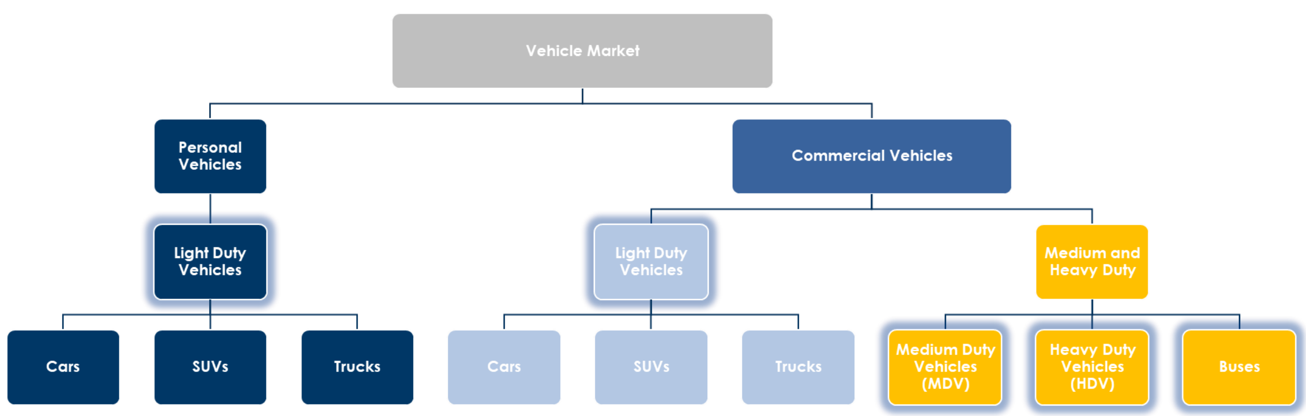
STUDY APPROACH

1. MARKET AND VEHICLE CHARACTERIZATION

To forecast adoption, the vehicle market is segmented and key data on annual vehicle sales, total fleet size, usage patterns, average fuel efficiency and other characteristics is collected for each segment. The analysis covers both personal vehicles and commercial vehicles/fleets, which have significantly different treatment of adoption decision making as a result of differences in economic decision-making thresholds and adoption barriers.

Due to differences in vehicle costs, usage patterns and EV availability, the market is further segmented into Light Duty Vehicles (LDV), Medium Duty Vehicles (MDV) and Heavy-Duty Vehicles (HDV). Where appropriate the market is segmented into more granular vehicle classes. For example, LDVs market is segmented into Cars, SUVs and Trucks. The figure below shows the used market segmentation.

Figure D - 2. Vehicle market segmentation



For each vehicle class, the analysis assumes adopters have a choice between three vehicle powertrains. With the assumption that ICE are the status quo vehicle choice, the model considers the adoption of two EV powertrains, which are defined as any vehicle that plugs in to charge. Specifically, those considered are:

- **BEV:** "Pure" electric vehicles that have only an electric powertrain and plug in to charge (E.g. Chevy Bolt, Nissan Leaf).
- **PHEVs:**[14] Hybrid vehicles that can plug in to charge and operate in electric mode for short distances (e.g. 30 km to 85 km), but that also include a combustion powertrain for longer trips (E.g. Chevy Volt, Toyota Prius Prime).

[14] Non-plug Hybrid Electric Vehicles (HEVs) and Fuel Cell Electric Vehicles (FCEV) are not included in the analysis. Additionally, MDV, HDV, and Bus EVs are only assumed to be BEVs.

For each vehicle class, assumptions on average vehicle characteristics (fuel consumption, powertrain size, battery size, etc.) are used to compile a representative model of vehicles within that segment. Additional assumptions on utilization (i.e. distance traveled) and operational costs are also compiled and used to calculate a bottom-up upfront vehicle cost and TCO for the different vehicle powertrains within each vehicle class.

2. MODEL CALIBRATION

Using data on vehicle sales, costs and other parameters, EVA was benchmarked to historical adoption in the province and key model parameters were calibrated to capture local market characteristics. Calibration parameters include:

- **Technology diffusion parameters**: Which determine rate of adoption of EVs in NL
- **Optimal public charging ratios**: Ideal EV/port ratio for L2 and DCFC infrastructure
- **Economic decision-making threshold**: Adopters' weighting of consideration for upfront cost versus TCO in adoption decision-making
- **PHEV/BEV Competition coefficient**: Level of competition between PHEVs and BEVs

Due to the limited EV deployment to date in NL, trends from the adoption of non-plug-in, hybrid electric vehicles (e.g. Toyota Prius and equivalent models) as well as data from other jurisdictions with similar characteristics and conditions were used to complement the calibration process.

3. MARKET ADOPTION PROJECTIONS

The calibrated version of the model was used to develop future-looking projections. The model was populated with NL-specific market data (see Model Inputs and Assumptions section), such as population density, electricity and fuel prices, local and regional charging infrastructure availability, home charging access, and other local market factors to project uptake of EVs out to 2035.

The model is used to project uptake under the following scenarios:

- **Baseline Projections:** Uptake under business-as-usual conditions[15] [16]
- **Sensitivity Analysis:** Sensitivity to key market, policy and technology uncertainties and risks, specifically
    - i. ***Global market competitiveness factors:*** *Battery costs, vehicle range, availability*
    - ii. ***Local factors:*** *Electricity rates, fuel prices*
- **Impact of Policy/Program Levers:** Key government or utility interventions that can support or accelerate the deployment of EVs in the province including:
    - i. ***Public Charger Deployment:*** *Direct Current Fast Chargers (DCFC) and Level 2 Chargers*
    - ii. ***Home Charging Access:*** *Incentives for home charger installations and programs to accelerate the availability of home charging access in Multi-Unit Residential Building (MURBs)*
    - ***iii.*** ***Vehicle Incentives:*** *Financial rebates for EVs*

For each scenario, the model outputs include both annual and cumulative number of vehicles sold (by vehicle powertrain for each vehicle class) as well as percentage of annual sales and fleet size.

4. UTILITY LOAD IMPACTS

Based on the projected EV adoption, an assessment of the impact of forecasted EVs on utility's load is conducted under different scenarios, each of which assume all charging happens within the Utilities' territories:

- **Annual electricity sales or consumption (GWh)** from EVs based on the assumed vehicle market composition, vehicle utilization, battery size and efficiency.
- **Impact on utility's load patterns and peak demand (MW**) using charging load profiles that consider the diversity of vehicle charging patterns (time and level of charging) and are scaled to match average vehicle utilization and characteristics.
- **Revenue opportunities** associated with EVs based on the increased energy sales and any incremental benefit streams.

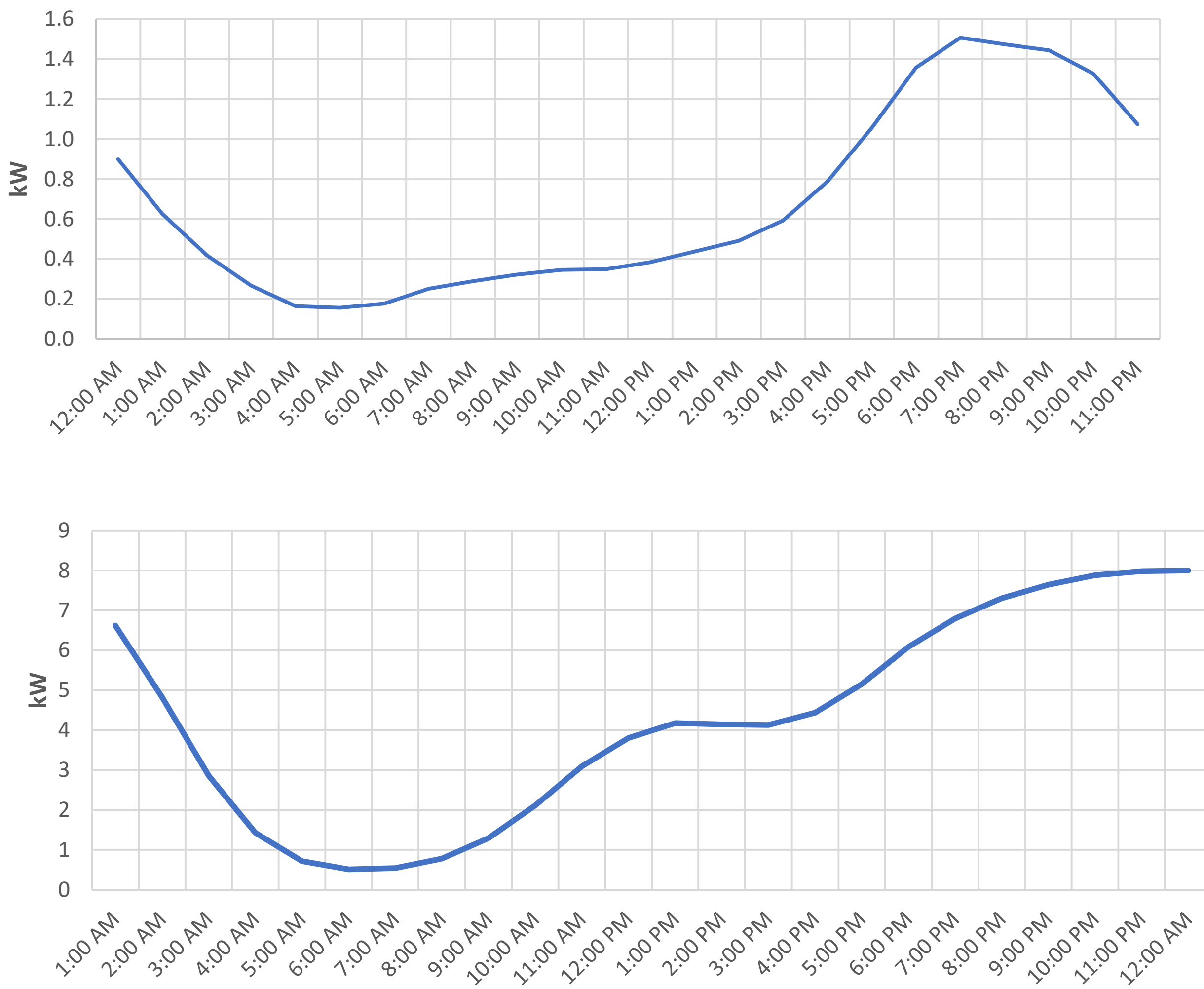
A diversified charging load profile was developed for each vehicle segment, leveraging data sets from a range of government and utility-led pilot programs. While the maximum rated power consumption of a single vehicle is important for considering the electrical load on a given home or even the impact on local

[15] Due to uncertainty around future availability of the incentive, the recently announced federal EV incentives are not included in the baseline scenario. The Low Incentive Investment Scenario was developed to resemble the federal rebate levels (i.e. Modeled Incentives – Low can be interpreted as impact of federal incentives). The modeled Incentives – High scenario can be interpreted as the federal incentive in addition to an incentive top-up by the utilities or government.

[16] Baseline scenario assumes existing committed actions by the utilities and government (estimated to be the installation of 14 DCFC and 30 Level 2 Ports in 2019/20).

distribution infrastructure due to clustering of EV adoption, system-wide impacts are best assessed using a diversified charging load profile which accounts for typical charging patterns across a larger population of EVs. For example, while a single LDV EV may be charged at a mix of Level 2 chargers (7 kW) and DCFC (50 kW+), considering the diversity in vehicle utilization and charging patterns, the system-wide peak load impact of the total LDV EV population is estimated at 1.5 kW of peak load. The load profiles developed for Personal LDVs and Commercial MDVs[17] are presented in **Figure D - 3**.

Figure D - 3. Diversified Charging Load Profiles for Personal Light-Duty Vehicle (Top) and Commercial Medium-Duty Vehicle (Bottom)



[17] Load patterns of medium-duty, heavy-duty, and buses were assumed to be the same, however for each segment a charging load profile was scaled according to the vehicle class-specific average charger power output assumption.

APPENDIX E: STUDY INPUTS AND ASSUMPTIONS

The Newfoundland and Labrador CDM Potential study model was populated with Newfoundland and Labrador-specific inputs to create a representative tool that captures the range and extent of energy saving opportunities in the province.

Key inputs include:

- **Utility Economic Data**: including rate projections; avoided costs of generation and supply; discount rates; inflation rates; number, type and stratified average consumption of customers; and CDM program activities and impacts.
- **Characterized Energy Saving Measures:** including measure costs (full and incremental), energy savings per unit, assumed market barrier level, market growth, replacement schedule, estimated life, applicable segments and populations, among others.
- **NL-Specific Market Data**: A wide range of market data was applied to assess each study element. These include the Commercial and Residential End-Use Surveys conducted in 2018 and 2017 respectively and market studies on various EE equipment and lighting socket studies. As part of this study, primary research was conducted via a barriers survey with 666 residential respondents and 150 commercial respondents, as well as 15 market actor interviews and two stakeholder sessions.

The following chapter provides an overview of the methods applied to characterize the full range of model inputs developed for this study.

UTILITY DATA

Over the course of project development, NL Utilities provided various data in response to a series of data requests. At the highest level, the data was used for the adoption, model inputs and model calibration. **Table E - 1** below details the majority of the data requested from the NL Utilities, and a brief description of how they were applied to the model.

Table E - 1: Utility Data Inputs

Data Provided	Purpose
Discount Rates • Discount rates applicable to CDM investments and savings. ***Utility discount rate:*** 6% Inputs Recommended by Dunsky: ***Participant discount rate:*** 4.95% (Prime Rate of 3.95% + 1%) ***Assumed inflation rate***: 2% - Bank of Canada inflationary targets	Applied to perform present value analysis of CDM investments and savings, which are a key model input for measure screening.
Avoided Costs • Annual avoided costs of electricity generation and demand, and fuel oil by year, including all components normally used in NL utilities' cost-effectiveness calculations. • On- and off-peak electricity avoided costs and other energy source costs provided by NL Utilities. Fuel oil prices were derived from the Board of Commissioners of Public Utilities. • **Demand avoided costs for Labrador Interconnected were estimated at 90% and Isolated Communities were estimated at 25% of the Island Interconnected avoided costs.**	The avoided costs are a principle component of the economic measure screening. Future years (beyond NL utilities' calculations) were extrapolated as necessary.
Marginal Retail Rates • Marginal rate savings – or the rate savings from energy efficiency measures - were calculated by market segment and sector. • For Labrador and Isolated Communities base rates, the following publication was used: Newfoundland and Labrador Hydro Schedule of Rates, Rules and Regulations (Jan 1st, 2019). • For Island Interconnected base rates, the utility provided three scenarios: Low, Mid and High. • To create the marginal customer rates, Dunsky identified the highest usage energy rate tier of each segment using market size and consumption data by segment. The rates were inflated to 2020 dollars. Then economy-wide inflation was removed from the rate escalation as the model takes economic inputs in real dollars. • See the customer rate tables below for the original rates for all three systems and the rates used from the Newfoundland and Labrador Hydro Schedule of Rates.	Energy billing rates were used as one input for calculating achievable potential. For each sector and segment, the most appropriate rate and rate block was selected based on rate definition/structure and customer characteristics (e.g., average consumption). Those rates are used to calculate the total customer bill impacts.

Data Provided	Purpose
Current Measure-Level Assumptions • NL Utilities measure assumptions, including program evaluation reports and program data.	Used for measure characterization development.
Codes and Standards • Codes and Standards assumptions (i.e., new codes and standards that will be enacted in the near future, their estimated year of enactment, and specification assumptions). See **Table E - 8** for specific codes and standards included.	Used to assess baseline conditions to calculate unit savings to be used in the analysis.
Program Data	
• CDM program descriptions, forecasts from NL Utilities' 2016-2020 CDM Plan. • Evaluated NL Utilities program results (2015-2018). • Newfoundland-specific barriers survey research (barriers data at the sector, segment, and end use-level).	Used to complement the measure-level analysis of unit savings and costs and to develop the programs' fixed and variable non-incentive costs.
Additional Information	
• Electricity energy and capacity forecasts (2019-2020) before CDM and codes and standards savings provided by NL Utilities. • Years 2030 and 2044 were forecasted using a linear regression model. • Non-electricity forecasts sourced from National Energy Board of Canada forecasts (https://apps2.neb-one.gc.ca/dvs/?page=landingPage&language=en).	Used to develop energy sales forecast for the 2020-2044 period.
NL Utilities Studies and Reports • Residential efficiency measure adoption.	Used to support measure characterization process and benchmark the adoption model results.
Non-identifying customer information • Contact information for a sample of residential and commercial/industrial customers.	Used to create a sample and obtain responses for the barrier/adoption surveys.

CUSTOMER RATES TABLES

Table E - 2: Island Interconnected - Low Rate Scenario

Year	Domestic Rate	GS Rate 2.1			GS Rate 2.3					GS Rate 2.4			
	All Customers	< 10 kW & 3500 kWh	>3500kWh										
	Energy Only	Energy Only	Demand GT 10 kW		Energy	Demand		Energy		Demand		Energy	
			Winter	Summer		Winter	Summer	1st 150 kWh/kVA & < 50000	excess	Winter	Summer	< 75000	excess
	¢/kWh	¢/kWh	$/kW	$/kW	¢/kWh	$/kVA	$/kVA	¢/kWh	¢/kWh	$/kVA	$/kVA	¢/kWh	¢/kWh
2019	13.78	13.65	11.33	8.30	10.22	9.55	6.52	11.63	9.35	9.18	6.16	11.21	9.26
2020	14.09	13.96	11.58	8.49	10.45	9.76	6.67	11.89	9.56	9.39	6.30	11.46	9.47
2021	14.42	14.29	11.85	8.69	10.70	9.99	6.83	12.17	9.79	9.61	6.45	11.73	9.69
2022	14.75	14.61	12.12	8.88	10.94	10.22	6.98	12.44	10.01	9.83	6.59	12.00	9.91
2023	15.08	14.94	12.39	9.08	11.19	10.45	7.14	12.72	10.23	10.05	6.74	12.27	10.13
2024	15.42	15.27	12.67	9.29	11.44	10.68	7.30	13.01	10.46	10.27	6.89	12.54	10.36
2025	15.77	15.62	12.96	9.50	11.69	10.92	7.46	13.30	10.70	10.51	7.05	12.82	10.59
2026	16.12	15.97	13.25	9.71	11.96	11.17	7.63	13.60	10.94	10.74	7.20	13.11	10.83
2027	16.48	16.33	13.55	9.93	12.23	11.42	7.80	13.91	11.19	10.98	7.37	13.41	11.08
2028	16.86	16.70	13.85	10.15	12.50	11.68	7.98	14.22	11.44	11.23	7.53	13.71	11.33
2029	17.23	17.07	14.16	10.38	12.78	11.94	8.16	14.54	11.69	11.48	7.70	14.02	11.58
2030	17.62	17.46	14.48	10.61	13.07	12.21	8.34	14.87	11.96	11.74	7.87	14.33	11.84
2031	18.02	17.85	14.81	10.85	13.37	12.48	8.53	15.20	12.23	12.01	8.05	14.66	12.11
2032	18.42	18.25	15.14	11.10	13.67	12.76	8.72	15.54	12.50	12.28	8.23	14.99	12.38
2033	18.84	18.66	15.48	11.35	13.97	13.05	8.91	15.89	12.78	12.55	8.42	15.32	12.66
2034	19.26	19.08	15.83	11.60	14.29	13.34	9.11	16.25	13.07	12.84	8.61	15.67	12.94
2035	19.70	19.51	16.18	11.86	14.61	13.64	9.32	16.62	13.36	13.12	8.80	16.02	13.23
2036	20.14	19.95	16.55	12.13	14.94	13.95	9.53	16.99	13.67	13.42	9.00	16.38	13.53

Year	Domestic Rate	GS Rate 2.1			GS Rate 2.3					GS Rate 2.4			
2037	20.59	20.40	16.92	12.40	15.27	14.26	9.74	17.37	13.97	13.72	9.20	16.75	13.84
2038	21.00	20.81	17.26	12.65	15.58	14.55	9.94	17.72	14.25	14.00	9.39	17.08	14.11
2039	21.48	21.27	17.65	12.93	15.93	14.88	10.16	18.12	14.57	14.31	9.60	17.47	14.43
2040	21.91	21.70	18.00	13.19	16.25	15.17	10.37	18.48	14.86	14.60	9.79	17.82	14.72
2041	22.34	22.13	18.36	13.46	16.57	15.48	10.57	18.85	15.16	14.89	9.98	18.17	15.01
2042	22.79	22.58	18.73	13.73	16.91	15.79	10.78	19.23	15.46	15.19	10.18	18.54	15.31
2043	23.25	23.03	19.10	14.00	17.24	16.10	11.00	19.61	15.77	15.49	10.39	18.91	15.62
2044	23.71	23.49	19.48	14.28	17.59	16.42	11.22	20.01	16.09	15.80	10.60	19.29	15.93
2045	24.19	23.96	19.87	14.57	17.94	16.75	11.44	20.41	16.41	16.12	10.81	19.67	16.25
2046	24.67	24.44	20.27	14.86	18.30	17.09	11.67	20.81	16.74	16.44	11.02	20.07	16.58
2047	25.16	24.93	20.68	15.15	18.66	17.43	11.91	21.23	17.07	16.77	11.24	20.47	16.91
2048	25.67	25.42	21.09	15.46	19.04	17.78	12.15	21.65	17.42	17.10	11.47	20.88	17.25
2049	26.18	25.93	21.51	15.77	19.42	18.13	12.39	22.09	17.76	17.44	11.70	21.29	17.59
2050	26.70	26.45	21.94	16.08	19.81	18.50	12.64	22.53	18.12	17.79	11.93	21.72	17.94
2051	27.24	26.98	22.38	16.40	20.20	18.87	12.89	22.98	18.48	18.15	12.17	22.15	18.30
2052	27.78	27.52	22.83	16.73	20.61	19.24	13.15	23.44	18.85	18.51	12.41	22.60	18.67
2053	28.34	28.07	23.29	17.07	21.02	19.63	13.41	23.91	19.23	18.88	12.66	23.05	19.04

Table E - 3: Island Interconnected - Mid Rate Scenario

Year	Domestic Rate	GS Rate 2.1			GS Rate 2.3					GS Rate 2.4			
	All Customers	< 10 kW & 3500 kWh	>3500kWh										
	Energy Only	Energy Only	Demand GT 10 kW		Energy	Demand		Energy		Demand		Energy	
			Winter	Summer		Winter	Summer	1st 150 kWh/kVA & < 50000	excess	Winter	Summer	< 75000	excess
	¢/kWh	¢/kWh	$/kW	$/kW	¢/kWh	$/kVA	$/kVA	¢/kWh	¢/kWh	$/kVa	$/kVA	¢/kWh	¢/kWh
2019	13.82	13.69	11.36	8.32	10.25	9.57	6.54	11.66	9.38	9.21	6.18	11.24	9.29
2020	14.55	14.41	11.96	8.76	10.79	10.08	6.89	12.28	9.87	9.70	6.50	11.84	9.78
2021	16.01	15.86	13.15	9.64	11.87	11.09	7.57	13.51	10.86	10.67	7.15	13.02	10.76
2022	17.61	17.44	14.47	10.60	13.06	12.20	8.33	14.86	11.95	11.73	7.87	14.32	11.83
2023	18.94	18.76	15.56	11.41	14.05	13.12	8.96	15.98	12.85	12.62	8.46	15.41	12.73
2024	19.33	19.15	15.89	11.64	14.34	13.39	9.15	16.31	13.12	12.88	8.64	15.73	12.99
2025	19.83	19.64	16.30	11.94	14.71	13.74	9.38	16.73	13.46	13.21	8.86	16.13	13.33
2026	20.09	19.90	16.51	12.10	14.90	13.92	9.51	16.95	13.63	13.39	8.98	16.34	13.50
2027	20.40	20.20	16.76	12.28	15.13	14.13	9.65	17.21	13.84	13.59	9.11	16.59	13.70
2028	20.86	20.66	17.14	12.56	15.47	14.45	9.87	17.60	14.16	13.90	9.32	16.97	14.02
2029	21.23	21.03	17.44	12.78	15.74	14.70	10.04	17.91	14.40	14.14	9.48	17.26	14.26
2030	21.64	21.44	17.78	13.03	16.05	14.99	10.24	18.26	14.69	14.42	9.67	17.60	14.54
2031	22.27	22.05	18.30	13.41	16.51	15.42	10.54	18.78	15.11	14.84	9.95	18.11	14.96
2032	22.63	22.42	18.60	13.63	16.79	15.68	10.71	19.09	15.36	15.08	10.11	18.41	15.21
2033	23.02	22.81	18.92	13.87	17.08	15.95	10.89	19.42	15.62	15.34	10.29	18.73	15.47
2034	23.56	23.34	19.36	14.19	17.47	16.32	11.15	19.88	15.99	15.70	10.53	19.16	15.83
2035	23.98	23.75	19.70	14.44	17.78	16.61	11.35	20.23	16.27	15.98	10.71	19.50	16.11
2036	24.49	24.26	20.12	14.75	18.17	16.96	11.59	20.66	16.62	16.32	10.94	19.92	16.46
2037	25.22	24.98	20.72	15.19	18.71	17.47	11.93	21.28	17.11	16.81	11.27	20.51	16.95
2038	25.89	25.65	21.28	15.59	19.21	17.93	12.25	21.84	17.57	17.25	11.57	21.06	17.40

Year	Domestic Rate	GS Rate 2.1			GS Rate 2.3					GS Rate 2.4			
2039	26.51	26.26	21.78	15.96	19.66	18.36	12.54	22.36	17.99	17.66	11.84	21.56	17.81
2040	27.04	26.78	22.22	16.28	20.05	18.73	12.79	22.81	18.34	18.01	12.08	21.99	18.17
2041	27.58	27.32	22.66	16.61	20.45	19.10	13.05	23.27	18.71	18.38	12.32	22.43	18.53
2042	28.13	27.86	23.11	16.94	20.86	19.48	13.31	23.73	19.09	18.74	12.57	22.88	18.90
2043	28.69	28.42	23.58	17.28	21.28	19.87	13.58	24.21	19.47	19.12	12.82	23.34	19.28
2044	29.27	28.99	24.05	17.62	21.71	20.27	13.85	24.69	19.86	19.50	13.08	23.80	19.66
2045	29.85	29.57	24.53	17.98	22.14	20.68	14.12	25.18	20.25	19.89	13.34	24.28	20.06
2046	30.45	30.16	25.02	18.34	22.58	21.09	14.41	25.69	20.66	20.29	13.61	24.76	20.46
2047	31.06	30.76	25.52	18.70	23.04	21.51	14.70	26.20	21.07	20.69	13.88	25.26	20.87
2048	31.68	31.38	26.03	19.08	23.50	21.94	14.99	26.72	21.49	21.11	14.15	25.77	21.29
2049	32.31	32.00	26.55	19.46	23.97	22.38	15.29	27.26	21.92	21.53	14.44	26.28	21.71
2050	32.96	32.64	27.08	19.85	24.45	22.83	15.59	27.80	22.36	21.96	14.73	26.81	22.15
2051	33.62	33.30	27.62	20.24	24.93	23.28	15.91	28.36	22.81	22.40	15.02	27.34	22.59
2052	34.29	33.96	28.18	20.65	25.43	23.75	16.22	28.93	23.27	22.85	15.32	27.89	23.04
2053	34.97	34.64	28.74	21.06	25.94	24.23	16.55	29.51	23.73	23.30	15.63	28.45	23.50

Table E - 4: Island Interconnected - High Rate Scenario

Year	Domestic Rate	GS Rate 2.1				GS Rate 2.3				GS Rate 2.4			
	All Customers	< 10 kW & 3500 kWh	>3500kWh										
	Energy Only	Energy Only	Demand GT 10 kW		Energy	Demand		Energy		Demand		Energy	
			Winter	Summer		Winter	Summer	1st 150 kWh/kVA & < 50000	excess	Winter	Summer	< 75000	excess
	¢/kWh	¢/kWh	$/kW	$/kW	¢/kWh	$/kVa	$/kVA	¢/kWh	¢/kWh	$/kVa	$/kVA	¢/kWh	¢/kWh
2019	13.10	12.98	10.76	7.89	9.72	9.07	6.20	11.05	8.89	8.73	5.85	10.65	8.80
2020	15.67	15.53	12.88	9.44	11.63	10.86	7.42	13.22	10.64	10.44	7.00	12.75	10.53
2021	22.49	22.28	18.48	13.55	16.68	15.58	10.64	18.98	15.26	14.99	10.05	18.29	15.11
2022	22.59	22.37	18.56	13.60	16.75	15.65	10.69	19.06	15.33	15.05	10.09	18.37	15.18
2023	22.98	22.77	18.89	13.84	17.05	15.92	10.88	19.39	15.59	15.31	10.27	18.69	15.44
2024	23.43	23.21	19.25	14.11	17.38	16.23	11.09	19.77	15.90	15.61	10.47	19.06	15.74
2025	24.08	23.86	19.79	14.50	17.86	16.68	11.40	20.32	16.34	16.05	10.76	19.59	16.18
2026	24.25	24.02	19.93	14.61	17.99	16.80	11.48	20.46	16.46	16.16	10.84	19.73	16.30
2027	24.50	24.27	20.13	14.75	18.17	16.97	11.59	20.67	16.62	16.33	10.95	19.93	16.46
2028	25.07	24.83	20.60	15.10	18.59	17.36	11.86	21.15	17.01	16.70	11.20	20.39	16.84
2029	25.42	25.18	20.89	15.31	18.85	17.61	12.03	21.44	17.25	16.94	11.36	20.68	17.08
2030	25.87	25.62	21.26	15.58	19.19	17.92	12.24	21.82	17.55	17.24	11.56	21.04	17.38
2031	26.72	26.47	21.96	16.09	19.82	18.51	12.64	22.54	18.13	17.81	11.94	21.74	17.96
2032	27.05	26.80	22.23	16.29	20.07	18.74	12.80	22.82	18.36	18.03	12.09	22.00	18.18
2033	27.43	27.17	22.54	16.52	20.34	19.00	12.98	23.14	18.61	18.28	12.26	22.31	18.43
2034	28.08	27.81	23.07	16.91	20.83	19.45	13.29	23.69	19.05	18.71	12.55	22.84	18.87
2035	28.49	28.22	23.41	17.16	21.13	19.73	13.48	24.03	19.33	18.98	12.73	23.17	19.14
2036	29.07	28.80	23.89	17.51	21.56	20.14	13.76	24.53	19.73	19.37	12.99	23.65	19.54
2037	30.09	29.80	24.72	18.12	22.32	20.84	14.24	25.38	20.42	20.05	13.44	24.47	20.22

Year	Domestic Rate	GS Rate 2.1				GS Rate 2.3				GS Rate 2.4			
2038	30.98	30.68	25.45	18.65	22.98	21.46	14.66	26.13	21.02	20.64	13.84	25.19	20.81
2039	31.73	31.43	26.08	19.11	23.54	21.98	15.02	26.77	21.53	21.14	14.18	25.81	21.32
2040	32.37	32.06	26.60	19.49	24.01	22.42	15.32	27.31	21.96	21.57	14.46	26.33	21.75
2041	33.02	32.70	27.13	19.88	24.49	22.87	15.62	27.85	22.40	22.00	14.75	26.85	22.18
2042	33.68	33.36	27.67	20.28	24.98	23.33	15.94	28.41	22.85	22.44	15.05	27.39	22.63
2043	34.35	34.02	28.23	20.69	25.48	23.79	16.25	28.98	23.31	22.89	15.35	27.94	23.08
2044	35.04	34.70	28.79	21.10	25.99	24.27	16.58	29.56	23.77	23.35	15.66	28.50	23.54
2045	35.74	35.40	29.37	21.52	26.51	24.75	16.91	30.15	24.25	23.81	15.97	29.07	24.01
2046	36.45	36.11	29.95	21.95	27.04	25.25	17.25	30.75	24.73	24.29	16.29	29.65	24.49
2047	37.18	36.83	30.55	22.39	27.58	25.75	17.59	31.37	25.23	24.77	16.61	30.24	24.98
2048	37.93	37.57	31.16	22.84	28.13	26.27	17.95	32.00	25.73	25.27	16.95	30.85	25.48
2049	38.68	38.32	31.79	23.30	28.69	26.79	18.30	32.64	26.25	25.78	17.29	31.46	25.99
2050	39.46	39.08	32.42	23.76	29.27	27.33	18.67	33.29	26.77	26.29	17.63	32.09	26.51
2051	40.25	39.86	33.07	24.24	29.85	27.88	19.04	33.95	27.31	26.82	17.98	32.73	27.04
2052	41.05	40.66	33.73	24.72	30.45	28.43	19.42	34.63	27.85	27.35	18.34	33.39	27.58
2053	41.87	41.48	34.41	25.22	31.06	29.00	19.81	35.33	28.41	27.90	18.71	34.06	28.14

The following table describes the original rates used for Labrador Interconnected and the Isolated Communities. These were taken from: Newfoundland and Labrador Hydro, Schedule of Rates, Rules and Regulations, Updated January 1, 2019.[18]

[18] https://nlhydro.com/wp-content/uploads/2019/02/2019-01-01-Complete.pdf

Table E - 5: Labrador Interconnected and Isolated Communities Rates

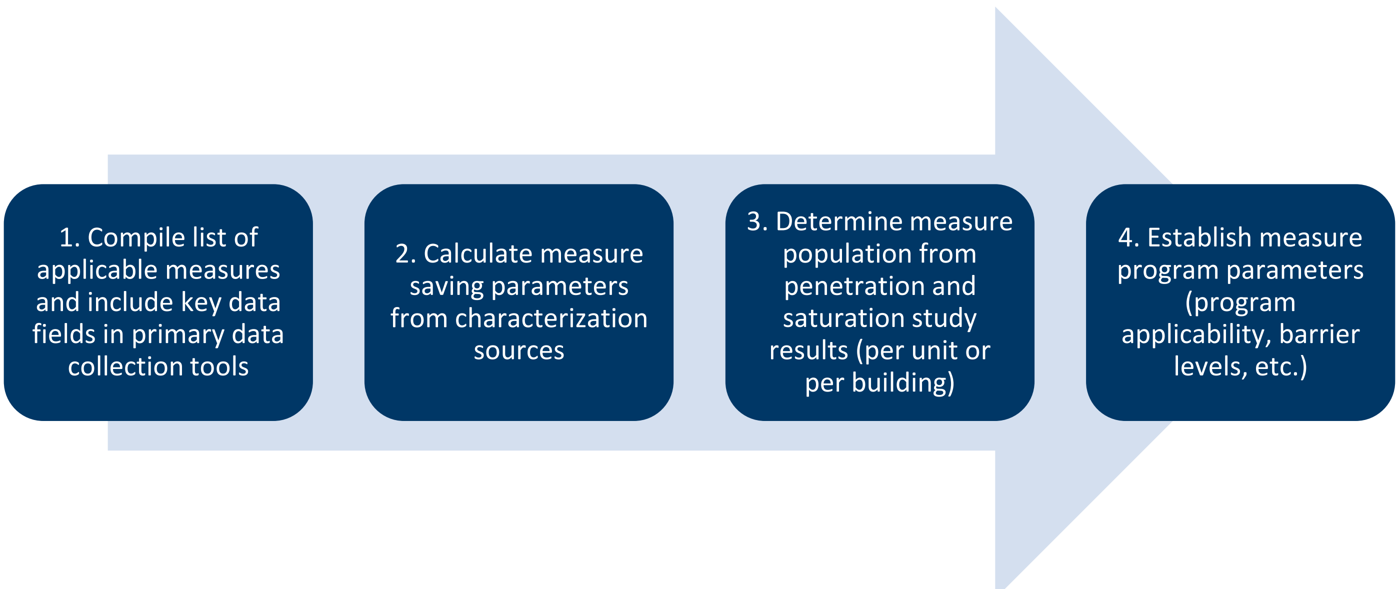
System	Sector	Rate Name	Page in Report	Energy Charge
Isolated Communities	Residential	Rate 1.2D – Domestic Diesel	DSL–NG-1	First Block : 11.391 ¢ per kWh Second Block : 12.838 ¢ per kWh Third Block : 17.408 ¢ per kWh
Isolated Communities	Commercial	Rate 2.1D – General Service Diesel 0-10 kW Rate 2.2D – General Service Diesel over 10 kW	DSL–NG-3 DSL–NG-4	17.250 ¢ per kWh 16.790 ¢ per kWh
Labrador Interconnected	Residential	Rate 1.1L – Domestic	LAB-1	3.255¢ per kWh
Labrador Interconnected	Commercial	Rate 2.1L – General Service 0-10 kW Rate 2.2L – GENERAL SERVICE 10 - 100 kW (110 kVA) Rate 2.3L - GENERAL SERVICE 110 kVA (100 kW) - 1000 kVA RATE No. 2.4L GENERAL SERVICE 1000 kVA AND OVER	LAB-2 LAB-3 LAB-4 LAB-5	5.092 ¢ per kWh 2.417 ¢ per kWh 2.090 ¢ per kWh 1.725¢ per kWh

ENERGY-SAVING MEASURES

The NL Utilities Potential study includes 2,181 measure-market combinations, representing the full range of commercially available technologies (current and emerging). The included measures were characterized using reputable TRMs from other jurisdictions, Dunsky's in-house database of energy efficiency measures in conjunction with market research to determine the population of energy saving opportunities for each measure, and the current baseline technology mix.

The measure characterization process steps outlined in **Figure E - 1** below was applied using a list of measures in consultation with the NL Utilities.

Figure E - 1: Measure Characterization Process



MEASURE CHARACTERIZATION

A list of measure options was presented to NL Utilities early in the project for approval. Basic assumptions related to energy savings or impact factors were developed based on information from TRMs from other jurisdictions, and Newfoundland and Labrador market and climate data.

The list was expanded and adapted based on feedback from NL Utilities, and a final approved measure list was compiled. A full list of measures characterized and their sources are presented in **Table E - 19** and **Table E - 20.**

MEASURE TYPES AND REPLACEMENT SCHEDULES

The model uses four types of measures:

- Replace on Burnout (ROB)
- Early Replacement (ER)
- Addition (ADD)
- New Construction/Installation (NEW)

Each of these measure types requires a different approach for determining the maximum yearly units available for potential calculations. **Table E - 6** provides a guide as to how each measure type is defined and how the replacement or installation schedule is applied within the Potential study to assess the phase-in potentials, year by year.

Table E - 6: Measures Types and Schedules Applied in the Potential study model

Measure Type	Description	Market Base	Yearly Units Calculation
Replace on Burnout (ROB)	Existing units are replaced by efficient units after they fail *Example: Replacing burned out bulbs with LEDs.*	Current Building Code/Equipment Standard or Industry Standard Practice.	Market[19]/Effective Useful Life (EUL) *The EUL is set at a minimum of 3 years[20] to spread installations over the potential study period.*
Early Replacement (ER)	Existing units are replaced by efficient units before burnout *Example: Early replacement of functional but inefficient furnaces.*	Existing (old) Units.	Market (old units)/10 years *The market is defined as the subset of the total number of existing units (e.g., old furnaces that could be retired early).*
Addition (ADD)	An EE measure is applied to existing equipment or structures *Example: Adding controls to existing lighting systems, adding insulation to existing buildings.*	Existing Units.	The eligible market is distributed over the estimated useful life of the measure using an S-curve function.
New Construction/ Installation (NEW)	Measures not related to existing equipment *Example: Installing a heat-pump in a newly constructed building.*	Building Code, equipment standard of Industry Standard Practice.	Market *Market base is measure-specific and defined as new units per year.*

[19] In this table, Market is defined as the number of units to which a specific measure applies.
[20] Note: The Home Energy Report is a special case with an EUL of one year.

For ROB measures, the number of existing equipment in a given year (after applying growth rates) is divided by the effective useful life (EUL) of the measure, to obtain a theoretical maximum number of units per year, which is further adjusted to account for factors such as technical constraints (applicability factor), competition groups, and market adoption rates. In cases for which there is a significant difference between the baseline EUL and the efficient technology EUL, the former is specified in the model and used for unit-per-year calculations. Measures based on a discretionary decision (referred to as an Addition Measure Type in **Table E - 6**) that can be implemented at any given point in time (insulation, controls) have been spread over a period dictated by the measure EUL. For some measures/markets, such as New Construction, the number of units per year is specified directly.

MEASURE MARKETS

Markets were largely determined from primary end use data collection of NL customers by MQO Research for the residential sector and by ICF for commercial sectors. For new construction measures and markets, a projected customer growth rate of 0.4% was applied, which corresponds to NL Utilities' anticipated annual residential and business customer growth rate as calculated from the 2018-2028 Load Forecast.

MEASURE FIELDS

For each measure included in the model, a range of specific fields were defined for entry into the model. These covered the following categories:

- **Applicable segment and sector:** These include the relevant rate class, sector and segment.
- **Measure population:** These fields include the number of buildings and equipment units (e.g. fans) or size units (e.g. horsepower of compressors).
- **Measure descriptions:** The descriptions include overviews of the applicable baseline technology (or technology mix) and efficient technology.
- **Measure annual gross savings:** Per-unit electric, including consumption and demand values.
- **Measure types**: For each measure, the installation timing relative to the EUL of the existing equipment is defined by the following:
    - Replace on Burnout (ROB)
    - Early Replacement (ER)
    - Additional Measures (ADD)
    - New Construction/Installation (NEW)
- **Measure costs:** Costs include both incremental and full costs (where available).
- **Measure life:** This category addresses the EUL of each measure and baseline technology as well as the Remaining Useful Life (RUL) for measures in which early replacement is applicable.
- **Measure adoption factors:** Adoption factors include market applicability factors and assigned barrier levels.
- **Impact factors:** These are factors affecting final savings, including net-to-gross adjustments, in-service factors, persistence factors and realization rates.

- **Load factors:** This category addresses summer and winter peak coincidence factors as well as seasonal savings distributions.

Fields are determined for each measure-segment combination, and the program factors are applied such that each measure is allocated to various programs.

NEW PROGRAM AND MEASURE RAMP-UP

For measures in the model that are not currently part of the CDM programs, the following uptake factor was applied to account for ramping up new programs and measure marketing.

Table E - 7: New Measure Uptake Factor

Program Ramp-up	Adoption	Cumulative
Year 1	10%	10%
Year 2	15%	25%
Year 3	20%	45%
Year 4	25%	70%
Year 5	30%	100%

UPDATED CODES AND STANDARDS

Over the course of the study, a number of new codes and standards will come into force. In some cases, these impact the efficiency of the baseline equipment and thereby can reduce the savings potential for the affected measures. All relevant codes and standards were considered, based on provincial standards in Newfoundland and Labrador, Federal Standards in Canada and upcoming Department of Energy (DOE) standards in the United States. The following details the equipment type, and energy source affected by codes and standards changes within the study.

Table E - 8: Codes and Standards incorporated in the study

Equipment Type	Applicable Code or Standard	Code Change Years
Air Source Heat Pumps	NRCan Standard (and future alignment with 2023 efficiencies in current U.S. DOE standard)	2023/2026
Mini-Split Ductless Heat Pump	NRCan Standard (and future alignment with 2023 efficiencies in current U.S. DOE standard)	2023/2026
LED Lamps and Reflectors	U.S. DOE - EISA	See below

LIGHTING CODES AND STANDARDS

Context

EISA Phase II is planned to come into effect in the United States on January 1, 2020, restricting the sale and manufacture of bulbs that do not meet EISA (US) requirements. These requirements are also anticipated to impact the Canadian market, as the Canadian government has indicated commitments to align efficiency standards with the US. As a result, Dunsky proposes a phase-out approach for affected programs that aligns with expected impacts and timing of the new regulation. Recent development in early February of 2019, namely the release of a *Notice Of Proposed Rulemaking* by the DOE to maintain the existing definitions of General Service Lamps and General Service Incandescent Lamps, will likely create the need to revisit the proposed approach as clarity is gained on future regulations.

EISA Implementation

Natural Resources Canada has provided notice that the minimum energy performance standards for general service and modified spectrum incandescent lighting are being considered for future amendments under the Energy Efficiency Regulations. Lighting products may be included in the next round of amendments, but as of yet these have not been planned. To estimate the process timeline for this amendment – and therefore the anticipated date of enforcement – historic examples were examined. A recent example, amendment 14, took three years to move from pre-consultation to enforcement of a new standard, which provides the basis of the assumption regarding lighting timelines.

It was assumed that the new lighting standards will be enforced in Canada beginning January 1, 2022, and a sell-through period will last through December 31, 2022. Starting January 1, 2023, savings from the purchase of new standard bulbs will no longer be counted towards programs. Starting January 1st, 2025, savings from the purchase of new specialty bulbs will no longer be counted towards programs.

Baseline

To estimate the baseline efficiency for existing bulb types and wattages, survey data that was collected in the Newfoundland and Labrador market for the residential sector was used.

- **Bulb types:** The distribution of bulb types used for the residential lighting measures came from Figure 11 of Newfoundland Power's 2018 Socket Saturation Survey. For commercial lighting measures, in the absence of CEUS market survey data on lighting, evaluated savings were used.
- **Wattages:** An assumed average bulb wattage of 60 Watt equivalents (We) was used (based on 13% of sales being 40We, 71% being 60We and 16% being 75W).

Interactive effects

An interactive effects factor was used to account for the impact of interior lighting measures on heating and cooling loads. For residential interior lighting measures, an interactive effects factor of 36% was applied based on the 2017-2018 Instant Rebates Program Evaluation. For commercial measures, the interactive effects in the 20% range from Table 29 in Econoler's report were used.

Interactive effects account for a portion of the lighting savings that would be made up by heating. These are applied in the model to impact the net savings from lighting measures.

Interactions among efficiency measures are captured in the Chaining function in the model, which assesses the degree to which measure mixes impact each other's savings. This is described in detail in Appendix A.

CLAIMING SAVINGS

In this study, any efficient measure affected by codes and standards but installed through a program before the codes and standards are enforced are attributed to the program throughout the measure lifetime. When the measure burns out and is replaced, the savings are then attributed to codes and standards changes. Savings for measures installed after the codes and standards are enforced are attributed to the codes and standards savings.

MEASURE CHARACTERIZATION INPUTS AND ASSUMPTIONS

The TRMs referenced in the following tables were used to develop measure characterization inputs and assumptions. In addition, the 2015 Potential Study and TRM developed by ICF for all sectors and systems were used for benchmarking purposes to compare current results with the past study.

Table E - 9: TRM versions used for commercial measures

Jurisdiction/TRM Name	Version
Iowa - Volume 3: Nonresidential Measures	Version 2 (July 12th, 2017)
Illinois - Volume 2: Commercial and Industrial Measures	Version 7.0 (Sep. 28th, 2018)
Massachusetts - 2019-2021 Plan Version	October 2018
Maine – Commercial/Industrial/Multifamily	Version 2018.3
Mid-Atlantic (Northeast Energy Efficiency Partnerships (NEEP))	Version 8.0 (May 2018)
New York - Residential, Multi-Family, and Commercial/Industrial Measures	Version 7 (April 15th, 2019)
PSEG Long Island	2019 Version, June 14, 2018
NB Power TRM	September 2017 version
OEB TRM	Version 3.0, December 3rd 2018
Pennsylvania TRM	June 2015 version
California TRM	3rd edition, 2017
Michigan Energy Measures Database	2019 Master Database

Table E - 10: TRM versions used for residential measures

Jurisdiction/TRM Name	Version
Iowa - Volume 2: Residential Measures	Version 2 (July 12th, 2017)
Illinois - Volume 3: Residential Measures	Version 7.0 (Sep. 28th, 2018)
Massachusetts - 2019-2021 Plan Version	October 2018
Maine - Retail/Residential	Version 2018.3
Mid-Atlantic (Northeast Energy Efficiency Partnerships (NEEP))	Version 8.0 (May 2018)
New York - Residential, Multi-Family, and Commercial/Industrial Measures	Version 7 (April 15th, 2019)
PSEG Long Island	2019 Version, June 14, 2018
NB Power TRM	September 2017 version

JURISDICTION SPECIFIC INPUTS

In order to ensure that the results accounted for the specific climatic and equipment usage conditions in each study zone, various measure characterization inputs were tailored to be specific to that zone. The tables below describe which inputs were adjusted, and show what values were used, for both the Commercial/Industrial measures and for the Residential measures.

COMMERCIAL AND INDUSTRIAL SECTOR

Table E - 11: Explanation of headings for jurisdiction specific tables in the C&I sector

Name	Description	Source
HDD_18.3C	Heating degree days (°C days) with a set point of 18.3°C (65°F)	http://ashrae-meteo.info/index.php?lat=47.620&lng=-52.750&place=''&wmo=718010&si_ip=SI&ashrae_version=2017
CDD_18.3C	Cooling degree days (°C days) with a set point of 18.3°C (65°F)	http://ashrae-meteo.info/index.php?lat=47.620&lng=-52.750&place=''&wmo=718010&si_ip=SI&ashrae_version=2017
HSPF_zone_IV_to_study_zone	Factor to convert HSPF from standard region IV to region V or VI	Rule of thumb used by NRCan
EFLH_heat <65kBtu/h	Equivalent full load hours for units under 5-tons	Mid-Atlantic methodology. Refer to C&I EFLH Calculations.xlsx
EFLH_heat > 65kBtu/h	Equivalent full load hours for units above 5-tons	Mid-Atlantic methodology. Refer to C&I EFLH Calculations.xlsx
EFLH_cool	Equivalent full load hours	Mid-Atlantic methodology. Refer to C&I EFLH Calculations.xlsx
HOU_lighting	Hours of operation for interior lighting	
HOU_compressor	Hours of operation of compressors	

Table E - 12: Zone 1 - Island Interconnected jurisdiction specific data for C&I sector

HDD_18.3C	CDD_18.3C	HSPF_zone_IV_to_study_zone
4,891	39	0.87

Segment	EFLH_heat_ < 65kBtu/h	EFLH_heat >65kBtu/h	EFLH_cool	HOU_lighting	HOU_compressor
Office	958	697	79	3,610	1,976
Retail	1,416	1,030	119	4,089	1,222
Grocery/Restaurant	2,424	1,763	229	5,592	1,976
Health Services	1,248	907	98	4,018	485
Education	1,427	1,038	115	3,255	520
Warehouse	746	542	58	3,759	1,324
Lodging/Hospitality/ MURB	2,718	1,977	236	1,533	1,976
Other Commercial	1,273	926	97	3,951	2,199
Fishing	1,273	926	97	4,394	1,630
Manufacturing	1,273	926	97	4,394	1,630
Small/Medium Industrial	1,273	926	97	4,394	1,630
Large Industrial	1,273	926	97	4,394	1,630

Table E - 13: Zone 2 - Labrador Interconnected jurisdiction specific data for C&I sector

HDD_18.3C	CDD_18.3C	HSPF_zone_IV_to_study_zone
7,126	28	0.76

Segment	EFLH_heat <65kBtu/h	EFLH_heat >65kBtu/h	EFLH_cool	HOU_lighting	HOU_compressor
Office	1,778	1,015	29	3,610	1,976
Retail	2,629	1,501	43	4,089	1,222
Grocery/Restau rant	4,500	2,568	83	5,592	1,976
Health Services	2,316	1,322	35	4,018	485
Education	2,649	1,512	42	3,255	520
Warehouse	1,384	790	21	3,759	1,324
Lodging/Hospit ality/ MURB	5,046	2,880	85	1,533	1,976
Other Commercial	2,363	1,349	35	3,951	2,199
Fishing	2,363	1,349	35	4,394	1,630
Manufacturing	2,363	1,349	35	4,394	1,630
Small/Medium Industrial	2,363	1,349	35	4,394	1,630
Large Industrial	2,363	1,349	35	4,394	1,630

Table E - 14: Zone 3 – Isolated Diesel jurisdiction specific data for C&I sector

HDD_18.3C	CDD_18.3C	HSPF_zone_IV_to_study_zone
6,289	0	0.76

Segment	EFLH_heat_ < 65kBtu/h	EFLH_heat >65kBtu/h	EFLH_cool	HOU_lighting	HOU_compressor
Office	1,232	896	0	3,610	1,976
Retail	1,821	1,324	0	4,089	1,222
Grocery/Restaurant	3,117	2,267	0	5,592	1,976
Health Services	1,604	1,167	0	4,018	485
Education	1,835	1,334	0	3,255	520
Warehouse	959	697	0	3,759	1,324
Lodging/Hospitality/ MURB	3,495	2,542	0	1,533	1,976
Other Commercial	1,637	1,191	0	3,951	2,199
Fishing	1,637	1,191	0	4,394	1,630
Manufacturing	1,637	1,191	0	4,394	1,630
Small/Medium Industrial	1,637	1,191	0	4,394	1,630
Large Industrial	1,637	1,191	0	4,394	1,630

RESIDENTIAL SECTOR

Table E - 15: Explanation of headings for jurisdiction specific tables in the residential sector

Name	Description	Source
HDD_18.3C	Heating degree days (°C days) with a set point of 18.3°C (65°F)	http://ashrae-meteo.info/index.php?lat=47.620&lng=-52.750&place=''&wmo=718010&si_ip=SI&ashrae_version=2017
CDD_18.3C	Cooling degree days (°C days) with a set point of 18.3°C (65°F)	http://ashrae-meteo.info/index.php?lat=47.620&lng=-52.750&place=''&wmo=718010&si_ip=SI&ashrae_version=2017
HSPF_zone_IV_to_study_zone	Factor to convert HSPF from standard region IV to region V or VI	Rule of thumb used by NRCan
AHL_kWH_out	Annual heating load (kWh) of average building in sector. Heat output of heating system, so independent of heating system efficiency.	NL data (Residential Data - January 27 2019) - processed by Dunsky.
EFLH_heat_hp	Equivalent full load hours of heating with a heat pump - residential sector	http://www.ieppec.org/wp-content/uploads/2018/05/Hamelin_paper_vienna.pdf
EFLH_heat_boiler	Equivalent full load hours of heating with a boiler - residential sector	https://puc.vermont.gov/sites/psbnew/files/doc_library/ev-technical-reference-manual.pdf
EFLH_heat_furnace	Equivalent full load hours of heating with a furnace - residential sector	https://puc.vermont.gov/sites/psbnew/files/doc_library/ev-technical-reference-manual.pdf
EFLH_cool	Equivalent full load hours of cooling - residential sector	https://puc.vermont.gov/sites/psbnew/files/doc_library/ev-technical-reference-manual.pdf
annual_energy_use_kWh_out	Annual electricity usage in an electrically heated building in sector (kWh)	NL data (Residential Data - January 27 2019) - processed by Dunsky.

Table E - 16: Zone 1- Island Interconnected jurisdiction specific data for residential sector

HDD_18.3C	CDD_18.3C	HSPF_zone_IV_to_study_zone
4,891	39	0.87

Segment	AHL _kWH_out	EFLH_heat _hp	EFLH_heat _boiler	EFLH_heat _furnace	EFLH _cool	annual_energy_use _kWh_out
Single Detached	13,507	900	907	1,147	100	23,061
Attached	10,112	900	907	1,147	100	17,733
Apartment	5,658	900	907	1,147	100	10,269

Table E - 17: Zone 2 - Labrador Interconnected jurisdiction specific data for residential sector

HDD_18.3C	CDD_18.3C	HSPF_zone_IV_to_study_zone
7,126	28	0.76

Segment	AHL _kWH_out	EFLH_heat _hp	EFLH_heat _boiler	EFLH_heat _furnace	EFLH _cool	annual_energy_use _kWh_out
Single Detached	19,677	1,311	1,322	1,671	73	29,232
Attached	14,731	1,311	1,322	1,671	73	22,352
Apartment	8,243	1,311	1,322	1,671	73	12,854

Table E - 18: Zone 3 – Isolated Diesel jurisdiction specific data for residential sector

HDD_18.3C	CDD_18.3C	HSPF_zone_IV_to_study_zone
6,289	0	0.76

Segment	AHL _kWH_out	EFLH_heat _hp	EFLH_heat _boiler	EFLH_heat _furnace	EFLH _cool	annual_energy_use _kWh_out
Single Detached	17,366	1,157	1,167	1,475	0	26,920
Attached	13,001	1,157	1,167	1,475	0	20,622
Apartment	7,275	1,157	1,167	1,475	0	11,886

MEASURE LIST AND CHARACTERISATION SOURCES

The measure lists and sources shown in the tables below were used to develop the characterisation algorithms and inputs. The new measure column indicates whether a measure exists in current CDM programs. The table also indicates where the inputs or algorithms were tailored to account for Newfoundland and Labrador-specific conditions.

COMMERCIAL AND INDUSTRIAL SECTOR

Table E - 19: Measure List and Sources for the C&I Sector[21]

#	Measure	New to CDM Programs	End Use	TRM Source	TRM Version	NL Adjustments
1	Roof Insulation	Yes	Envelope	NB	2017	HDD/CDD by climate zone for each electricity system
2	Wall Insulation	Yes	Envelope	NB	2017	HDD/CDD by climate zone for each electricity system
3	Building Shell Air Sealing	Yes	Envelope	IA	2017	HDD/CDD by climate zone for each electricity system
4	Efficient Windows	Yes	Envelope	NY	2019	HDD/CDD by climate zone for each electricity system
5	LEED Certified	Yes	Envelope	Custom	Custom	HDD/CDD by climate zone for each electricity system
6	Net-Zero Ready	Yes	Envelope	Custom	Custom	HDD/CDD by climate zone for each electricity system
7	LED A-Lamp (Interior)	No	Lighting	NB	2017	Lighting HOU and interactive effects adapted for NL
8	LED Reflector (Interior)	No	Lighting	NB	2017	Lighting HOU and interactive effects adapted for NL
9	Linear LED Tube	No	Lighting	NB	2017	Lighting HOU and interactive effects adapted for NL
10	LED Luminaire	Yes	Lighting	PSEGLI	2017	Lighting HOU and interactive effects adapted for NL
11	LED High Bay	No	Lighting	NB	2017	Adjusted Savings as per NL Power program evaluation.
12	LED Exit Sign	No	Lighting	NB	2017	Adjusted Savings as per NL Power program evaluation.
13	LED A-Lamp (Exterior)	No	Lighting	NB	2017	Lighting HOU adapted for NL
14	LED Reflector (Exterior)	No	Lighting	NB	2017	Lighting HOU adapted for NL
15	LED Parking Garage (Exterior)	Yes	Lighting	ME	2018	Lighting HOU adapted for NL

[21] All measures outside of new construction are considered under the Utilities Custom Business program if the project is deemed cost effective.

#	Measure	New to CDM Programs	End Use	TRM Source	TRM Version	NL Adjustments
16	LED Pole Mounted (Exterior)	Yes	Lighting	NB	2017	Lighting HOU adapted for NL
17	LED Wall Pack (Exterior)	No	Lighting	ME	2018	Lighting HOU adapted for NL
18	LED Refrigerated Case Lighting	Yes	Lighting	PSEGLI	2018	Lighting HOU adapted for NL
19	Lighting Controls (Interior), Daylighting	No	Lighting	NB	2017	Lighting HOU adapted for NL
20	Lighting Controls (Interior), Occupancy	No	Lighting	NB	2017	Lighting HOU adapted for NL
21	Lighting Controls (Exterior)	Yes	Lighting	ME	2018	Lighting HOU adapted for NL
22	Unitary Air Conditioner	Yes	HVAC	NEEP	2018	EFLH by climate zone for each electricity system
23	Room/Wall-Mounted Air Conditioner (RAC)	Yes	HVAC	IA	2017	EFLH by climate zone for each electricity system
24	Package Terminal Air Conditioner (PTAC)	Yes	HVAC	PSEGLI	2018	EFLH by climate zone for each electricity system
25	Mini-split Ductless Heat Pump (DHP) - Cold Climate	Yes	HVAC	NEEP	2018	EFLH and equipment efficiencies adapted by climate zone for each electricity system
26	Air Source Heat Pumps (ASHP) - Cold Climate	No	HVAC	NEEP	2018	EFLH and equipment efficiencies adapted by climate zone for each electricity system
27	Air Source Heat Pumps (ASHP)	No	HVAC	NEEP	2018	EFLH and equipment efficiencies adapted by climate zone for each electricity system
28	Ground Source Heat Pump	Yes	HVAC	NB	2017	EFLH and equipment efficiencies adapted by climate zone for each electricity system
29	Package Terminal Heat Pump (PTHP)	Yes	HVAC	PSEGLI	2018	EFLH adapted by climate zone for each electricity system
30	Water Cooled Chiller, Centrifugal	Yes	HVAC	PSEGLI	2018	EFLH adapted by climate zone for each electricity system
31	Air Cooled Chiller	Yes	HVAC	PSEGLI	2018	EFLH adapted by climate zone for each electricity system
32	Energy Recovery Ventilator (ERV)	Yes	HVAC	OEB	2018	EFLH adapted by climate zone for each electricity system
33	Air Curtains	Yes	HVAC	IL	2019	EFLH adapted by climate zone for each electricity system

#	Measure	New to CDM Programs	End Use	TRM Source	TRM Version	NL Adjustments
34	HVAC EC Motor	Yes	HVAC	MA	2016	HDD/CDD by climate zone for each electricity system
35	Demand Control Ventilation (DCV)	Yes	HVAC	IL	2017	HDD/CDD by climate zone for each electricity system
36	Kitchen Demand Control Ventilation	Yes	HVAC	IL	2017	Annual heating load adapted by climate zone for each electricity system
37	Dual Enthalpy Economizer Controls	Yes	HVAC	NB	2017	HDD/CDD by climate zone for each electricity system
38	Energy Management System (EMS)	Yes	HVAC	Custom	Custom	Deemed savings adjusted based on energy consumption per business for each electricity system.
39	Guest Room Energy Management	Yes	HVAC	IA	2017	Deemed savings adjusted based on energy consumption per business for each electricity system.
40	Programmable Thermostat	No	HVAC	MA	2017	Savings based on heating equipment and NL climate zones
41	Advanced Thermostat (Wi-Fi Thermostat)	No	HVAC	MA	2017	Savings based on heating equipment and NL climate zones
42	Heat Pump Water Heaters	Yes	Hot Water	PA	2015	Adjusted savings based on estimated hot water consumption of each NL segment.
43	Faucet Aerator	Yes	Hot Water	IA	2017	Adjusted savings based on estimated hot water consumption of each NL segment.
44	Low Flow Shower Head	No	Hot Water	NB	2017	Adjusted savings based on estimated hot water consumption of each NL segment.
45	Pre-Rinse Spray Valve	No	Hot Water	NY	2017	Adjusted savings based on estimated hot water consumption of each NL segment.
46	Thermostatic Restrictor Shower Valve	Yes	Hot Water	NEEP	2018	Adjusted savings based on estimated hot water consumption of each NL segment.
47	Recirculation Pump with Demand Controls	Yes	Hot Water	IA	2017	Adjusted savings based on estimated hot water consumption of each NL segment.
48	Circulator Pump EC Motor	Yes	Hot Water	ME	2018	Adjusted savings based on estimated hot water consumption of each NL segment.

#	Measure	New to CDM Programs	End Use	TRM Source	TRM Version	NL Adjustments
49	Dishwasher	Yes	Kitchen	IA	2017	Adjusted savings based on estimated hot water consumption of each NL segment.
50	Fryer	Yes	Kitchen	MA	2015	No adjustments made
51	Oven	Yes	Kitchen	MA	2015	No adjustments made
52	Steamer	Yes	Kitchen	MA	2015	No adjustments made
53	Refrigerated Case Anti-Sweat Door Heaters	Yes	Refrigeration	PSEGLI	2018	No adjustments made
54	Refrigerated Case Door Gaskets	Yes	Refrigeration	NY	2017	No adjustments made
55	Refrigerated Case Night Cover	Yes	Refrigeration	MA	2017	No adjustments made
56	Refrigerated Walk-ins Door Strip	Yes	Refrigeration	IA	2017	No adjustments made
57	ENERGY STAR Ice Maker	Yes	Refrigeration	MA	2017	No adjustments made
58	CEE Rated Refrigerators and Freezer - Recycling	Yes	Refrigeration	Custom	Custom	Dropped - Not cost effective
59	Refrigerated Case EC Motor	No	Refrigeration	PSEGLI	2018	No adjustments made
60	Refrigerated Walk-ins EC Motor	No	Refrigeration	PSEGLI	2018	No adjustments made
61	Refrigerated Walk-ins Evaporator Fan Control	Yes	Refrigeration	PSEGLI	2018	No adjustments made
62	Refrigeration Heat Recovery	Yes	HVAC	Custom	Custom	No adjustments made
63	HVAC VFD - Cooling Tower	Yes	Motor/ Compressor	NB	2017	Adjusted kwh/hp based on NL segments
64	HVAC VFD - Fan	Yes	Motor/ Compressor	NB	2017	Adjusted kwh/hp based on NL segments
65	HVAC VFD - Pump	Yes	Motor/ Compressor	NB	2017	Adjusted kwh/hp based on NL segments
66	High Efficiency Air Compressor	Yes	Motor/ Compressor	PSEGLI	2018	Adjusted based on NL compressor HOU for each segment.

#	Measure	New to CDM Programs	End Use	TRM Source	TRM Version	NL Adjustments
67	Air Receiver for Load/No Load Compressor	Yes	Motor/ Compressor	PSEGLI	2018	Adjusted based on NL compressor HOU for each segment.
68	Low Pressure Drop Filters	Yes	Motor/ Compressor	IL	2018	Adjusted based on NL compressor HOU for each segment.
69	Zero Loss Condensate Drain	Yes	Motor/ Compressor	NB	2017	Adjusted based on NL compressor HOU for each segment.
70	Refrigerated Air Dryer	Yes	Motor/ Compressor	PSEGLI	2019	Adjusted based on NL compressor HOU for each segment.
71	Motor Controls - Process	Yes	Motor/ Compressor	NB	Custom	Applied to Industrial segments
72	Motor Controls - Conveyors	Yes	Motor/ Compressor	Custom	Custom	Applied to Industrial segments
73	Motor Controls - Pumps	Yes	Motor/ Compressor	Custom	Custom	Applied to Industrial segments
74	Custom Processes	No	Process	Custom	Custom	Applied to Industrial segments
75	Advanced Smart Strips	Yes	Office Equipment	PA	2016	No adjustments made
76	ENERGY STAR Uninterruptable Power Supply	Yes	Other	CA	2016	No adjustments made
77	Computer Room Air Conditioner (CRAC)	Yes	Other	MI	2019	EFLH by climate zone for each electricity system
78	Solar Thermal	Yes	Other	Custom	Custom	Savings based on NL climate zones
79	Retro-commissioning Strategic Energy Manager (RCx SEM)	Yes	Other	Custom	Custom	Deemed savings adjusted based on energy consumption per business for each electricity system.

RESIDENTIAL SECTOR

Table E - 20: Measure List and Sources for the Residential Sector

#	Measure	New to CDM Programs	End Use	TRM Source	TRM Version	NL Adjustments
1	Air Purifier	Yes	Appliance	blank	blank	No adjustments
2	ENERGY STAR Clothes Dryers	Yes	Appliance	NEEP	2018	No adjustments
3	Clothes Washer	Yes	Appliance	NEEP	2018	Adjusted based on ratio of front to top loading clothes washers in NL.
4	Dehumidifier	No	Appliance	NL Instant Rebates Program Evaluation	2018	Used NL evaluated savings
5	Dehumidifier Recycle	Yes	Appliance	MA	2019	No adjustments
6	Dishwasher	Yes	Appliance	NEEP	2018	No adjustments
7	Freezer	Yes	Appliance	NEEP	2018	No adjustments
8	Freezer Recycle	Yes	Appliance	California Public Utility Commission Appliance Recycling Program Impact Evaluation	2014	No adjustments
9	Heat Pump Clothes Dryers	Yes	Appliance	NEEP	2018	No adjustments
10	Refrigerator	Yes	Appliance	NEEP	2018	No adjustments
11	Refrigerator Recycle	Yes	Appliance	California Public Utility Commission Appliance Recycling Program Impact Evaluation	2014	No adjustments
12	Home Energy Report	No	Behavioral	NL 2018 Benchmarking Program Evaluation	2019	Used NL evaluated savings
13	Professional Air Sealing	Yes	Envelope	IA	2018	Savings adjusted based on HDD and CDD for each electricity system.
14	Attic Insulation	No	Envelope	IL	2019	Used NL evaluated savings

#	Measure	New to CDM Programs	End Use	TRM Source	TRM Version	NL Adjustments
15	Basement Insulation	No	Envelope	NL Insulation Rebate Program Evaluation	2017	Used NL evaluated savings
16	Efficient Windows	Yes	Envelope	IA	2018	Savings adjusted based on HDD and CDD for each electricity system.
17	New Home Construction	Yes	Envelope	Energy Star Certified Homes, Version 3 (Rev. 08)	2016	Used savings value for NL's climate zone.
18	Wall Insulation	Yes	Envelope	IL	2019	Savings adjusted based on HDD and CDD for each electricity system.
19	Faucet Aerator	No	Hot Water	NL Instant Rebates Program Evaluation	2018	Used NL evaluated savings
20	Heat Pump Water Heater (HPWH)	Yes	Hot Water	NY	2019	Savings adjusted based on HDD and CDD for each electricity system.
21	Low Flow Shower Head	No	Hot Water	NL Instant Rebates Program Evaluation	2018	Used NL evaluated savings
22	Thermostatic Restrictor Shower Valve	Yes	Hot Water	NEEP	2018	Adjusted based on mean number of people and of showerheads in NL.
23	Air Source Heat Pump (ASHP) Tune Up	Yes	HVAC	IA	2017	Adjusted based on heat pump equivalent full load hours for NL.
24	Duct Insulation	Yes	HVAC	ME	2018	Savings adjusted based on HDD and CDD for each electricity system.
25	Duct Sealing	Yes	HVAC	IA	2018	Savings adjusted based on HDD and CDD for each electricity system.
26	ENERGY STAR Ceiling Fan	No	HVAC	NEEP	2018	No adjustments
27	Ground Source Heat Pump (GSHP)	Yes	HVAC	NEEP	2018	Savings adjusted based on average annual heating load for each electricity system.
28	Heat Recovery Ventilator	No	HVAC	Custom	Custom	Used Take Charge program requirement as efficient level SRE.

#	Measure	New to CDM Programs	End Use	TRM Source	TRM Version	NL Adjustments
29	Mini-split Ductless Heat Pump (DMSHP) - Cold Climate	Yes	HVAC	MA	2019	Savings adjusted based on heat pump equivalent full load hours and on heat pump efficiency in that zone.
30	Thermostat Programmable	No	HVAC	NEEP	2018	Savings adjusted based on average annual heating load for each electricity system and on average number of thermostats per household.
31	Thermostat Wi-Fi	No	HVAC	NEEP	2018	Savings adjusted based on average annual heating load for each electricity system and on average number of thermostats per household.
32	LED A-Lamp (exterior)	No	Lighting	PSEGLI	2018	Baseline bulb power based on NL bulb mix based on 2018 Socket Saturation Survey.
33	LED A-Lamp (interior)	No	Lighting	PSEGLI	2018	Baseline bulb power based on NL bulb mix based on 2018 Socket Saturation Survey.
34	LED Linear Tube	Yes	Lighting	NEEP	2018	No adjustments
35	LED Reflector (exterior)	No	Lighting	PSEGLI	2018	Baseline bulb power based on NL bulb mix based on 2018 Socket Saturation Survey.
36	LED Reflector (interior)	No	Lighting	PSEGLI	2018	Baseline bulb power based on NL bulb mix based on 2018 Socket Saturation Survey.
37	Advanced Smart Strips	No	Other	NL Instant Rebates Program Evaluation	2018	Used NL evaluated savings
38	Convection Oven	Yes	Appliance	Custom	Custom	No adjustments
39	Crawl Space Insulation	No	Envelope	IL	2019	Savings adjusted based on HDD and CDD for each electricity system.
40	ENERGY STAR Doors	Yes	Envelope	IA	2018	Savings adjusted based on HDD and CDD for each electricity system.
41	Air Source Heat Pump (ASHP) - Cold Climate	Yes	HVAC	MA	2019	Savings adjusted based on heat pump equivalent full load hours and on heat pump efficiency in that zone.

#	Measure	New to CDM Programs	End Use	TRM Source	TRM Version	NL Adjustments
42	Electronic Thermostat	No	HVAC	NEEP	2018	Savings adjusted based on average annual heating load for each electricity system.
43	Dimmer Switches	No	Lighting	NL Instant Rebates Program Evaluation	2018	Used NL evaluated savings
44	Lighting Controls (Interior)	No	Lighting	MA	2019	Baseline bulb power based on NL bulb mix based on 2018 Socket Saturation Survey.
45	Lighting Controls (Exterior)	No	Lighting	MA	2019	Baseline bulb power based on NL bulb mix based on 2018 Socket Saturation Survey.
46	Insulated Hot Tub Covers	Yes	Other	Custom	Custom	No adjustments

Additionally, in all cases where NL's programs allow the measure to be implemented in a home with oil space heating/water heating, the space heating/water heating savings were split between electricity and oil according to the ratio of the proportion of buildings heated by each of those fuels in that zone and segment.

The following measures are only applicable for electrically heated homes:

a. Home energy report[22]
b. Air Sealing
c. Attic Insulation
d. Basement Insulation
e. Efficient Windows
f. Wall insulation
g. Crawl space insulation
h. Energy star doors
i. All heat pumps
j. New home construction
k. Electronic, programmable and Wi-Fi thermostats – both room and central

[22] Currently the Newfoundland and Labrador Utilities' customers without electric heat are enrolled in this program.

Custom methods were used when a suitable TRM could not be found. **Table E - 21** below details the assumptions made in the case of the custom measures.

Table E - 21: Assumptions for Custom Measures

Measure	Inputs	Algorithm used
Heat Recovery Ventilator	***Flow rate*** based on ventilation requirements in Canada's 2010 National Building Code from http://rdh.com/wp-content/uploads/2015/12/HRV_Guide_for_Houses.pdf. ***Base SRE level*** from https://www.exec.gov.nl.ca/exec/occ/publications/efficient_home_building_guide.pdf. ***Efficient SRE level*** based on takeCHARGE program requirements. Used average of SRE requirement at 0 and -25 C. ***EUL*** from Wisconsin Focus on Energy 2018 TRM.	Energy saving = energy in exhaust air * difference in SRE between efficient and baseline version * proportion of heating provided by each type of heating system / efficiency of that heating system.
Convection Oven	***Savings percentage*** and ***oven baseline power*** from https://smarterhouse.org/cooking/energy-saving-tips. ***Oven HOU*** based on professional judgement. ***EUL*** from NRCAN's Energy cost calculator for new appliances.	Energy saving = Savings percentage * oven baseline power * oven hours of use per day.
Insulated Hot Tub Covers	***Savings percentage*** based on Analysis of Standards Options for Portable Electric Spas, Davis Energy Group Energy Solutions - 2004. ***Baseline consumption*** from Hydro Quebec's Spa consumption calculator - assumed spa used once or twice a week. Used average of all year consumption and summer only consumption. ***EUL*** from https://lakeshorepoolsandtubs.com/2017/11/08/replacing-your-hot-tub-cover/.	Energy saving = savings percentage * baseline energy use.

FURTHER MEASURES CONSIDERED

A number of measures were considered for the study but were ultimately not retained in the modeling. The table below provides a list of these measures and the rationale behind their omission.

Table E - 22. Omitted Measures and Rationale

Measure	Rationale
	RESIDENTIAL
Downsizing HVAC capacity	Prevalence of central HVAC systems in residential units are low with only 13% of homes in the province having an electric furnace, central air source heat pump or ground source heat pump. High efficiency heat pumps are covered in the study, however additional savings from downsizing HVAC is estimated to be small. As well, cost and comfort are barriers to downsizing HVAC capacity.
Codes support program	Most new home construction is happening in major centres, such as St. John's, Mount Pearl, Paradise and Conception Bay South, where the building code is being enforced. For example, close to 60% of new residential service connections in 2018 were on the Avalon peninsula.
Recirculating shower system	Recirculating shower systems are included as a commercial measure, but not for single family homes, as energy used by the pumps will offset hot water savings.
Tankless water heater	Tankless water heaters could increase peak demand. There are other significant barriers to the installation of this measure, including that many customer electrical panels would require additional amperage.
Water tank insulation / Super insulated tanks	New tanks are typically already well insulated.
Drain Water Heat Recovery	Typically hard to configure for single-family residential and is not cost-effective.
Air conditioners and AC tune-ups	Very low prevalence of AC units in NL.
High-Efficiency Furnace Blower Motor	Almost all savings lost to interactive effects.
Timers for Car Warmers	No REUS data on this was available, and Newfoundland is not typically considered to be cold enough to warrant car block heaters.
Use Sensor for Clothes Dryer	Some new clothes dryers have moisture sensors but this is not a retrofit measure.

Measure	Rationale
High Efficiency Cooktops (Induction)	Minimal evidence of consistent savings.
	COMMERCIAL / INDUSTRIAL
VendingMiser	VendingMiser was considered in Newfoundland and Labrador's 2015 Potential Study. In the study it was identified that savings were not likely to exist past 2023.
Codes support program	In the new Climate Change Action Plan the Provincial Government committed to establish minimum energy efficiency requirements for commercial and institutional buildings, which will help address available savings.
Drain water heat recovery	This is typically just appropriate for NC MURBS - a significant potential for retrofit due to building stack configurations and installation costs/challenges is not seen.
CEE Rated Refrigerators and Freezers	CEE retired its specification for commercial refrigerators and freezers as of March 27, 2017 in order to focus on other opportunities to advance energy savings in commercial foodservice.
Automatic Door Closers (Walk-in Coolers)	Minimal applications and impacts.
Freeze Defrost Controllers	Minimal applications and impacts.
ENERGY STAR computers and office equipment	This is not typically considered to be a decision-making factor for computer purchase. NTGs would be very low.
Phase change materials (PCMs)	The technology is in an early phase and does not have proven savings.
Custom Behavioural	Savings for this type of measure were captured under Retro-commissioning and Strategic Energy Manager (RCx and SEM)
Boiler Reset Controls and Steam Traps	In Dunsky's experience this equipment usually applies to gas or oil-fired boilers.

CONSERVATION DEMAND MANAGEMENT PROGRAMS

The Potential Study organizes measures into CDM programs that are characterized by their applicable market coverage, incentive levels and administrative costs. Wherever possible, the programs were developed based on current NL Utilities' programs. Baseline inputs were created for each program and were used to define scenarios as outlined below.

PROGRAM CHARACTERIZATION METHODOLOGY

Programs were largely characterized based on current NL Utilities' programs, following a series of steps to ensure methodological consistency. The Potential study does include some measures not currently offered within the Utilities' portfolio; however, in these cases additional programs were characterized based on other jurisdictions and discussion with Utility staff.

GATHERING AND COMPILING PROGRAM DATA

As a first step, data was gathered on existing programs from the NL 2016-2020 Five-Year Conservation Demand Management Plan, as well as available program evaluation reports. From the compiled list of programs, the Dunsky team aggregated and extracted expected program net savings and costs. To calculate the program costs, the following cost streams were considered to be administrative:

- Program Planning and Administration
- Marketing and Advertising
- Sales, Technical Assistance and Training
- Evaluation and Market Research

The list in **Table E - 23** below highlights the programs characterized for this Potential study.

Table E - 23: NL Utilities Programs

System(s)	Sector	Program
IIC & LAB	Residential	Insulation and envelope
		Energy efficient product rebates
		Thermostats
		HVAC
		Heat pumps
		Benchmarking
		Residential new construction
		Appliance recycling
	Commercial	Business efficiency program
		Commercial new construction
	Industrial	Industrial efficiency program
ISO	Residential	Isolated systems residential program
	Commercial	Isolated systems business efficiency program

PROGRAM INPUT PARAMETERS

The Dunsky team characterized the programs highlighted above and developed assumptions using a uniform methodology, with final adjustments made based on professional judgement and feedback from NL Utilities.

Each program input (listed below) was characterized based on data received from NL Utilities.

- **Fixed Administration Costs are defined as program costs that do not change with the potential model measure uptake.** Through conversations with NL Utilities staff, the portion of non-incentive administrative costs that are fixed (independent of savings) were identified on a program-by-program basis. Costs were taken from the CDM model and converted to real 2020 dollars, then mapped to each program to produce annual fixed costs.
- **Variable Administration Costs are defined as program costs that change with the potential measure uptake.** Also, through conversations with NL Utilities staff, the portion of non-incentive administrative costs considered to be variable (change in magnitude with savings) were identified on a program-by-program basis. Costs were taken from the CDM model and converted to real 2020 dollars, then mapped to each program to produce variable costs by program ($/kWh).
- **Incentive levels are the portion of measure incremental costs that are covered by program incentives.** These incentive levels vary by scenario to assess the ability for higher incentive levels to drive participation:
    - Where available, current NL Utilities incentive levels were calculated using reported participant incentive and participant cost values:

I = Incentive (%)

PI = Participant Incentive ($)

IC = Measure Incremental Cost ($)

$$I = \frac{PI}{(PI + IC)}$$

In cases where data was not available, incentive levels were identified in conversation with the Utilities' staff.

- **Barrier Reductions refer to the ability of programs to reduce market barriers through effective marketing and delivery.**[23] Barrier reductions via program enabling strategies were defined for each scenario. Further discussion of the barrier levels and their impact on adoption is included in Appendix A.
- **The Cost-Effectiveness Threshold indicates the minimum TRC ratio for which a measure can be included in the program**. This can be lowered to allow non-cost-effective measures to be included into the programs. For all scenarios, the default ratio of 0.8 was used.

The program inputs common among all three achievable potential scenarios are provided in **Table E - 24** below.

[23] While the DOE has published 5 different adoption curves for extreme, high, medium, low and no barriers, the Dunsky team's adoption model further provides intermediate barrier curves to provide a more refined analysis. Adjacent DOE barrier levels are considered separated by one step.

Table E - 24: Program Model Inputs by Scenario

	Incentive Level			Barrier Reduction		
Program Name	Lower	Mid	Upper	Lower	Mid	Upper
Insulation and envelope	60%	65%	65%	0	0	0.5
Energy efficient product rebates	20%	35%	35%	0	0	0.5
Thermostats	30%	45%	45%	0	0	0.5
HVAC	50%	60%	60%	0	0	0.5
Heat pumps	0%	50%	50%	0	0	0.5
Benchmarking[24]	30% of homes	40% of homes	50% of homes	n/a	n/a	n/a
Residential new construction[25] **(NEW)**	0%	30%	30%	0	0.5	1
Appliance recycling (NEW)	0%	50%	75%	0	0.5	1
Business efficiency program	20%	30%	30%	0	0	0.5
Commercial new construction (NEW)	0%	30%	30%	0	0.5	1
Industrial efficiency program	30%	50%	50%	0	0	0.5
Isolated systems residential efficiency program	100%	100%	100%	0	0	0.5
Isolated systems business efficiency program	80%	85%	85%	0	0	0.5

[24] The benchmarking program (Home Energy Reports) carries no incremental cost to the customer and its impact is determined by the portion of homes that received the Home Energy Reports. Program incentive levels and barrier reductions used as inputs in the model are defined as work arounds to result in the Lower, Mid and Upper program scenario coverage values of 30%, 40% and 50% respectively.

[25] For new programs (those not currently offered as part of the NL Utilities CDM portfolio) a 0.5 barrier reduction was included for the Mid scenario, and a full barrier level reduction in the Upper scenario to account for the initial barrier reduction from the new program promotional materials.

PRIMARY RESEARCH

DESCRIPTION

In addition to the utility and program data incorporated in the Potential study, the Dunsky team conducted primary research with residential and commercial/industrial (C&I) customers to assess barriers in implementing energy efficiency measures and gain additional market insights where required. Research consisted of surveys for both residential and C&I customers, and market actor interviews with individuals who have subject-matter expertise into particular details required for the study. Results from the surveys and interviews complemented work already conducted by the Utilities to provide a better understanding of technology availabilities and customer behaviours and motivations.

BARRIERS SURVEYS

Residential Survey

The Residential survey was conducted as an online survey with the following parameters:

- A sample of 4,000 customers was selected from all Newfoundland Power and Newfoundland and Labrador Hydro customers for which the Utilities had email addresses.
- The surveys were developed to be 10-12 minutes in length, with a goal of 400 completes.
- The survey was kept open for two weeks to ensure adequate time was available for responses.

By the survey's close, 666 responses were received, with results tabulated by utility and residential segment:

Table E - 25: Breakdown of Residential Survey Responses by Utility and Residential Segments

Data Point	Number of Responses	Breakdown
Total Responses	666	
Segment	533	Single Family Detached
	38	Attached (Duplex or Triplex)
	20	Townhouse or Row House
	27	Apartment or Condo 2-4 Units
	17	Apartment or Condo >5 Units
	9	Mobile Home or Trailer
	22	Other (Vacation Home, Hotel, etc.)
Occupant Status	559	Owners
	96	Renters

The survey covered barriers to adopting the following categories of energy efficiency measures:

- Insulation
- Air sealing
- Heating systems
- Heat pumps
- Appliances
- Smart thermostats

In addition, the survey assessed residential customer considerations to participating in demand response/demand control and fuel switching initiatives.

Commercial/Industrial Survey

The C&I survey was conducted via telephone with the following parameters:

- A random, stratified sample of customers were selected from all Newfoundland Power and Newfoundland and Labrador Hydro customers. Stratification was based on the need for responses from each of the following segments:
  - Office
  - Retail
  - Other
  - Lodging
  - Health
  - Education
  - Warehouse
  - Manufacturing
  - Grocery/Restaurant
  - Fishing
- The surveys were developed to be 10-12 minutes in length, with a goal of 150 completes, with final responses as follows:

Table E - 26: Breakdown of Commercial/Industrial Survey Responses by Utility and Segments

Data Point	Number of Responses	Breakdown
Total Responses	150	
Segment	29	Office
	21	Retail
	20	Other
	16	Lodging
	15	Health
	15	Education
	10	Warehouse
	9	Manufacturing
	8	Grocery/Rest
	7	Fishing

The survey covered barriers to adopting energy efficiency equipment and participating in demand response/demand control and fuel switching initiatives.

BARRIER SETTING FOR MODEL INPUTS

The results of the surveys were used as inputs to the potential study using the following steps:

1. Barriers were set at the segment and end-use level based on the barrier survey results.
2. For each end-use, barriers were established based on the average response on 3-5 specific questions considering key customer constraints that could hinder conducting an energy efficiency upgrade: cost, available time, customer knowledge, project complexity, and uncertainty over the benefits.
3. Global factors were then applied to each segment based on financial decision-making and the proportion of respondents who own or rent the building.
4. Labrador barriers were increased ½ step above the Island Interconnected system.
5. Isolated diesel barriers were increased ½ step above the Island Interconnected system.

MARKET ACTOR INTERVIEWS

Fifteen one-on-one interviews were scheduled with individuals who have subject-matter expertise in the following residential and commercial energy efficiency areas:

- Lighting
- Heat Pumps
- Fish Plants
- Educational Facilities
- Residential Insulation
- Large Industrial
- Commercial New Construction
- Plumbing (Commercial and Residential)
- Mechanical Needs (Commercial and Residential)
- Electric Vehicles
- Fuel Switching

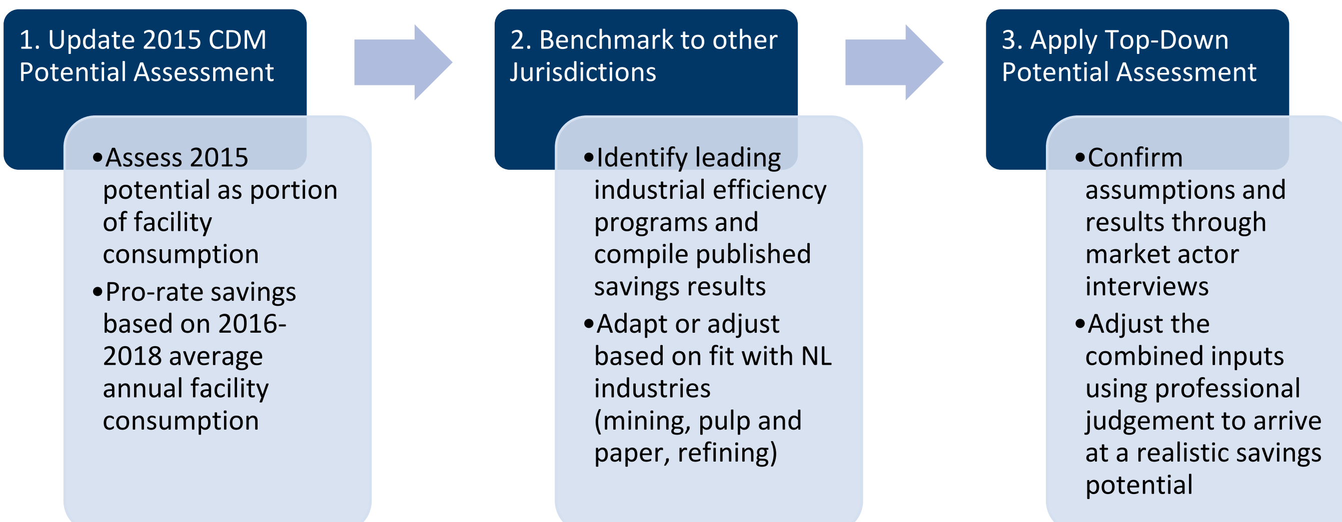
The semi-structured, qualitative interviews were intended to provide supplemental detail on measure and/or market considerations, depending on the specific technologies, sectors, or initiatives identified above. Some examples include Newfoundland and Labrador-specific costs, penetration of given technologies within the provincial market, barriers to adoption, and facility-specific characteristics.

LARGE INDUSTRIAL SECTOR TOP-DOWN ASSESSMENT

As part of the NL Conservation Potential Study, Dunsky attempted to assess the efficiency potential in Newfoundland and Labrador's large industrial segment. This segment is comprised of six transmission-level customers of Newfoundland and Labrador Hydro (two in the LAB system, and four connected to the IIC system) who collectively represent a significant portion of energy consumption in the province (35%).

The utility market data collected through the CEUS did not include these customers, and very little is known about these customers' installed systems, or the penetration of energy efficient equipment. As a result, based on the minimal information available for these customers regarding realistic equipment saturation counts or square footage of operating spaces, this data was not applied in the bottom-up potential model. To address this challenge, a top-down approach was applied to assess the potential among these six transmission-level customers. This is based on the central assumption that because the NL Utilities have not run large industrial CDM programs over the majority of time that has passed since the 2015 CDM Potential study, the overall pool of efficiency opportunities should, in theory, remain largely the same as it was in 2015.

Figure E - 2: Large Industrial Top-Down Potential Assessment Process



LARGE INDUSTRIAL POTENTIAL: TOP-DOWN ASSESSMENT RESULTS AS INPUTS TO STUDY

Because the CEUS did not include the six transmission-level industrial customers, and little is known about the saturation and penetration of energy using equipment in these facilities, it was not possible to include them in Dunsky's bottom-up efficiency potential model. Thus, a top-down assessment of the efficiency savings was performed by extrapolating the findings from the 2015 Newfoundland and Labrador CDM Potential Study. An overview of the top-down assessment results that were included as inputs to the savings and program scenarios in this study is provided in **Table E - 27** below.

Table E - 27: Top-Down Efficiency Potentials for Transmission Level Industrial Customers Applied in Study (expressed as portion of sales to Transmission Level Customers)

Scenario	Technical Potential (2034)	Economic Potential (2034)	Cumulative Achievable Savings (2034)	Annual Program Savings Range	Annual Average
High (ICF 2015)	IIC: 33% LAB: 13%	IIC: 27% LAB: 10%	IIC: 24% LAB: 9.3%	0.70% - 1.0%	0.87%
Mid (New)			IIC: 18% LAB: 6.8%	0.48% - 0.77%	0.62%
Low (ICF 2015)			IIC: 11.2% LAB: 4.4%	0.23% - 0.53%	0.38%

Table E - 28: Top-Down Efficiency Potentials for Transmission Level Industrial Customers Applied in Study: Consumption (GWh)

Jurisdiction	% Industrial Electricity Savings	Jurisdiction Characteristics [26][27]
NB Power	0.54%-0.58%	Main industries: Paper, wood products, refined petroleum, mining. Industrial electricity rate: ≈6.64¢/kWh[28]
Wisconsin Focus on Energy	0.60%	Main industries: Paper, manufacturing (Food, Plastics, machinery, others). Industrial electricity rate: 10.5¢/kWh 29th place in 2018 ACEEE State Scorecard
IESO (Ontario)	0.76%	Main industries: Mining, metals, manufacturing, food and beverage, automotive. Industrial electricity rate: 12.0¢/kWh[29]
Energy Trust of Oregon	0.79%	Main industries: Wood products, water treatment, laundry, cannabis. 7th place in 2018 ACEEE State Scorecard Industrial electricity rate: 8.7¢/kWh
Efficiency Vermont	1.2%	Main industries: Agriculture/farming, manufacturing (precision machining, plastics, composites, semiconductors, medical devices). Industrial electricity rate: 14.7¢/kWh 4th place in 2018 ACEEE State Scorecard

[26] American Council for an Energy-Efficient Economy (2018), *The 2018 State Energy Efficiency Scorecard*
[27] USA States average industrial electricity rates retrieved from: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a for February 2019, with an exchange rate of 1.34 CAD/USD
[28] Average of NB Power's small industrial and large industrial rates, assuming a customer capacity factor of 60%
[29] Ontario electricity costs retrieved from http://www.ieso.ca/en/Corporate-IESO/Media/Year-End-Data for supply and https://hydroottawa.com/accounts-and-billing/business/rates-and-conditions for delivery

Table E - 29: Top-Down Efficiency Potentials for Transmission Level Industrial Customers Applied in Study: Consumption (GWh)

Consumption savings from Efficiency																
Program Savings																
Island Transmission-Level Savings (GWh)	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Technical	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19
Economic	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
High	10	11	11	11	12	12	12	12	13	13	13	14	14	14	14	15
Mid	7	7	8	8	8	8	9	9	9	9	10	10	10	11	11	11
Low	3	4	4	4	5	5	5	5	6	6	6	6	7	7	7	8
Labrador Transmission-Level Savings (GWh	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Technical	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27
Economic	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22
High	15	16	16	17	17	18	18	19	19	19	20	20	21	21	21	22
Mid	10	11	11	12	12	12	13	13	14	14	14	15	15	16	16	17
Low	5	5	6	6	7	7	8	8	8	9	9	10	10	11	11	11
Cumulative Savings	**Assumed EUL = 10 years on average for savings**															
Island Transmission-Level Savings (GWh)	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Technical	19	37	56	74	93	112	130	149	167	167	167	167	167	167	185	204
Economic	15	30	45	60	75	90	105	120	135	135	135	135	135	135	150	164
High	10	21	32	43	55	67	79	92	105	107	110	113	115	117	132	147
Mid	7	14	21	29	37	46	55	63	73	75	78	81	83	85	96	108
Low	3	7	11	15	20	25	30	35	41	43	46	49	51	54	61	69
Portion of Sales - Island																
Technical	3%	6%	9%	12%	15%	18%	21%	24%	27%	27%	27%	27%	27%	27%	30%	33%
Economic	2%	5%	7%	10%	12%	15%	17%	20%	22%	22%	22%	22%	22%	22%	25%	27%
High	1.7%	3.4%	5.2%	7.1%	9.0%	10.9%	13.0%	15.0%	17.1%	17.6%	18.0%	18.4%	18.9%	19.3%	21.6%	24.0%
Mid	1.1%	2.3%	3.5%	4.8%	6.1%	7.5%	8.9%	10.4%	11.9%	12.4%	12.8%	13.2%	13.6%	14.0%	15.8%	17.6%
Low	0.5%	1.1%	1.8%	2.5%	3.2%	4.0%	4.9%	5.8%	6.7%	7.1%	7.5%	8.0%	8.4%	8.8%	10.0%	11.2%
Labrador Transmission-Level Savings (GWh	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Technical	27	55	82	110	137	165	192	220	247	275	275	275	275	275	275	275
Economic	22	44	67	89	111	133	155	177	200	222	222	222	222	222	222	222
High	15	31	47	64	81	99	117	136	155	174	178	183	187	191	196	200
Mid	10	21	32	43	55	68	81	94	107	122	126	130	135	139	143	147
Low	5	10	16	23	29	36	44	52	60	69	73	78	82	86	90	94
Portion of Sales - Labrador																
Technical	1%	3%	4%	5%	6%	8%	9%	10%	11%	13%	13%	13%	13%	13%	13%	13%
Economic	1%	2%	3%	4%	5%	6%	7%	8%	9%	10%	10%	10%	10%	10%	10%	10%
High	0.7%	1.4%	2.2%	3.0%	3.8%	4.6%	5.4%	6.3%	7.2%	8.1%	8.3%	8.5%	8.7%	8.9%	9.1%	9.3%
Mid	0.5%	1.0%	1.5%	2.0%	2.6%	3.1%	3.7%	4.4%	5.0%	5.7%	5.9%	6.1%	6.3%	6.5%	6.7%	6.8%
Low	0.2%	0.5%	0.8%	1.0%	1.4%	1.7%	2.0%	2.4%	2.8%	3.2%	3.4%	3.6%	3.8%	4.0%	4.2%	4.4%

Table E - 30: Top-Down Efficiency Potentials for Transmission Level Industrial Customers Applied in Study: Peak Demand (MW)

Demand Savings from Efficiency																	
Cumulative Savings																	
	Island Transmission-Level Savings (MW)	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
	Technical	2.4	4.9	7.3	9.7	12.1	14.6	16.9	19.2	21.6	21.6	21.6	21.6	21.6	21.6	24.0	26.4
	Economic	2.0	3.9	5.9	7.8	9.8	11.8	13.6	15.5	17.5	17.5	17.5	17.5	17.4	17.4	19.4	21.3
	High	1.3	2.7	4.2	5.7	7.2	8.7	10.3	11.9	13.5	13.9	14.2	14.6	14.9	15.2	17.1	19.0
	Mid	0.9	1.8	2.8	3.8	4.9	6.0	7.1	8.2	9.4	9.8	10.1	10.4	10.8	11.1	12.5	13.9
	Low	0.4	0.9	1.4	2.0	2.6	3.2	3.9	4.6	5.3	5.6	6.0	6.3	6.6	6.9	7.9	8.9
	Portion of Annual Peak - Island																
	Technical	3%	6%	9%	12%	15%	18%	21%	24%	27%	27%	27%	27%	27%	27%	30%	33%
	Economic	2%	5%	7%	10%	12%	15%	17%	20%	22%	22%	22%	22%	22%	22%	25%	27%
	High	2%	3%	5%	7%	9%	11%	13%	15%	17%	18%	18%	18%	19%	19%	22%	24%
	Mid	1.1%	2.3%	3.5%	4.8%	6.1%	7.5%	8.9%	10.4%	11.9%	12.4%	12.8%	13.2%	13.6%	14.0%	15.8%	17.6%
	Low	0.5%	1.1%	1.8%	2.5%	3.2%	4.0%	4.9%	5.8%	6.7%	7.1%	7.5%	8.0%	8.4%	8.8%	10.0%	11.2%
	Labrador Transmission-Level Savings (MW)	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
	Technical	4	8	12	16	19	23	27	31	35	39	39	39	39	39	39	39
	Economic	3	6	9	13	16	19	22	25	28	31	31	31	31	31	31	31
	High	2	4	7	9	12	14	17	19	22	25	25	26	27	27	28	28
	Mid	1	3	4	6	8	10	11	13	15	17	18	18	19	20	20	21
	Low	1	1	2	3	4	5	6	7	9	10	10	11	12	12	13	13
	Portion of Annual Peak - Labrador																
	Technical	1%	3%	4%	5%	6%	8%	9%	10%	11%	13%	13%	13%	13%	13%	13%	13%
	Economic	1%	2%	3%	4%	5%	6%	7%	8%	9%	10%	10%	10%	10%	10%	10%	10%
	High	1%	1%	2%	3%	4%	5%	5%	6%	7%	8%	8%	9%	9%	9%	9%	9%
	Mid	0.5%	1.0%	1.5%	2.0%	2.6%	3.1%	3.7%	4.4%	5.0%	5.7%	5.9%	6.1%	6.3%	6.5%	6.7%	6.8%
	Low	0.2%	0.5%	0.8%	1.0%	1.4%	1.7%	2.0%	2.4%	2.8%	3.2%	3.4%	3.6%	3.8%	4.0%	4.2%	4.4%

PORTFOLIO BENCHMARKING INPUTS AND SOURCES

The table below compares savings from efficiency programs from other Canadian provinces across residential, commercial and industrial and cross-cutting sectors.

Table E - 31: Efficiency Program Savings from Other Canadian Provinces (2015-2018 depending on Location)

Programs	NB Power	BC Hydro	Efficiency NS	Hydro Quebec	Manitoba Hydro	SaskPower
Total annual incremental electricity savings from measures installed (% of retail sales)	0.42%	1.0%	1.3%	0.31%	0.86%	0.2%
Total Savings (GWh)	**55**	**602**	**131**	**524**	**190**	**56**
Residential	50	50	54	203	24	25.3
Commercial	5	102	55	321	58	30.8
Industrial	0	166	22		17	
Cross-cutting	0.5	284			91	
Total retail sales (GWh)	**13,170**	**57,652**	**10,245**	**170,703**	**21,966**	**23,282**
Residential	5,100	18,068	4,374	66,111	7,250	3,162
Commercial	2,332	18,968	3,060	45,816	6,873	5,190
Industrial	4,479	13,177	2,466	53,699	7,843	13,722
Other	1,259	7,439	345	5,077		1,208
Total lifetime electricity savings as a % of retail sales	4.8%	12.0%	14.7%	3.5%	9.9%	2.8%
Residential	10.0%	10.1%	13.7%	3.4%	11.0%	7.7%
Commercial & Industrial	0.8%	13.1%	15.5%	3.6%	9.4%	1.8%

Table E - 32: Sources for Data in Table E - 30

NB Power	Savings: 2019/2020 DSM Initiative Update Retail Sales: 2017/2018 Annual Report
BC Hydro	Savings: Report on Demand-Side Management Activities for Fiscal 2017 Retail Sales: 2015-2017 Annual Service Plan Report
Efficiency NS	Savings: Efficiency One 2017 Annual Report Retail Sales: Emera Annual Report 2017
Hydro Quebec	Savings: Sustainability Report 2017 Retail Sales: Annual Report 2017
Manitoba Hydro	Savings: Supplemental Report to the Power Smart Plan 2014 to 2017 - Appendix 8.1 Retail Sales: Annual Report 2016-2017
SaskPower	Savings and Retail Sales: SaskPower 2017-2018 Annual Report Retail Sales:

DEMAND RESPONSE

The demand response potential study branch covers multiples steps. This section focuses on the inputs and assumptions used to complete this study. DR potential methodology was covered in Appendix B.

The demand response modelling used general utility data described in this Appendix (see Utility Data). Key inputs for demand response include:

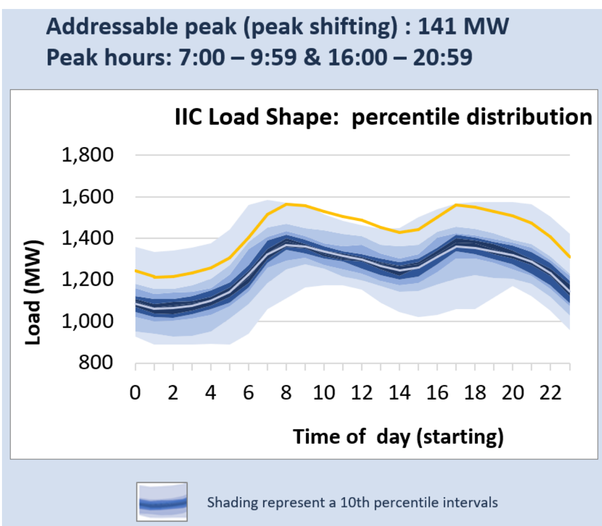
- Avoided costs
- Demand forecast
- Discount rates

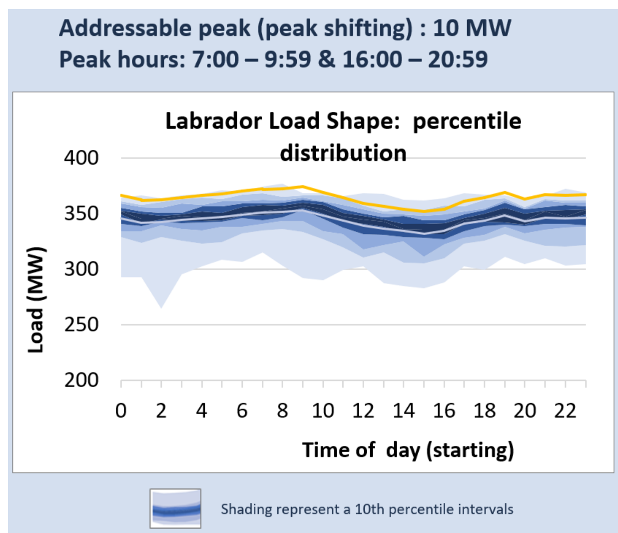
STANDARD PEAK DAY

NL Utilities provided Dunsky with hourly historical load data. For the IIC, the data covered January 1st, 2015 to March 31st, 2019 (37,233 data points) and for the LAB, the data covered January 1st, 2015 to December 31st, 2018 (35,064 data points).

This historical data was used to create standard peak days for both systems.

Figure E - 3: Standard Peak Day for IIC and LAB





END-USE BREAKDOWNS

Dunsky developed end-use load curves for each market sector and end-use and where relevant, for individual segments. These provide a basis for four study processes:

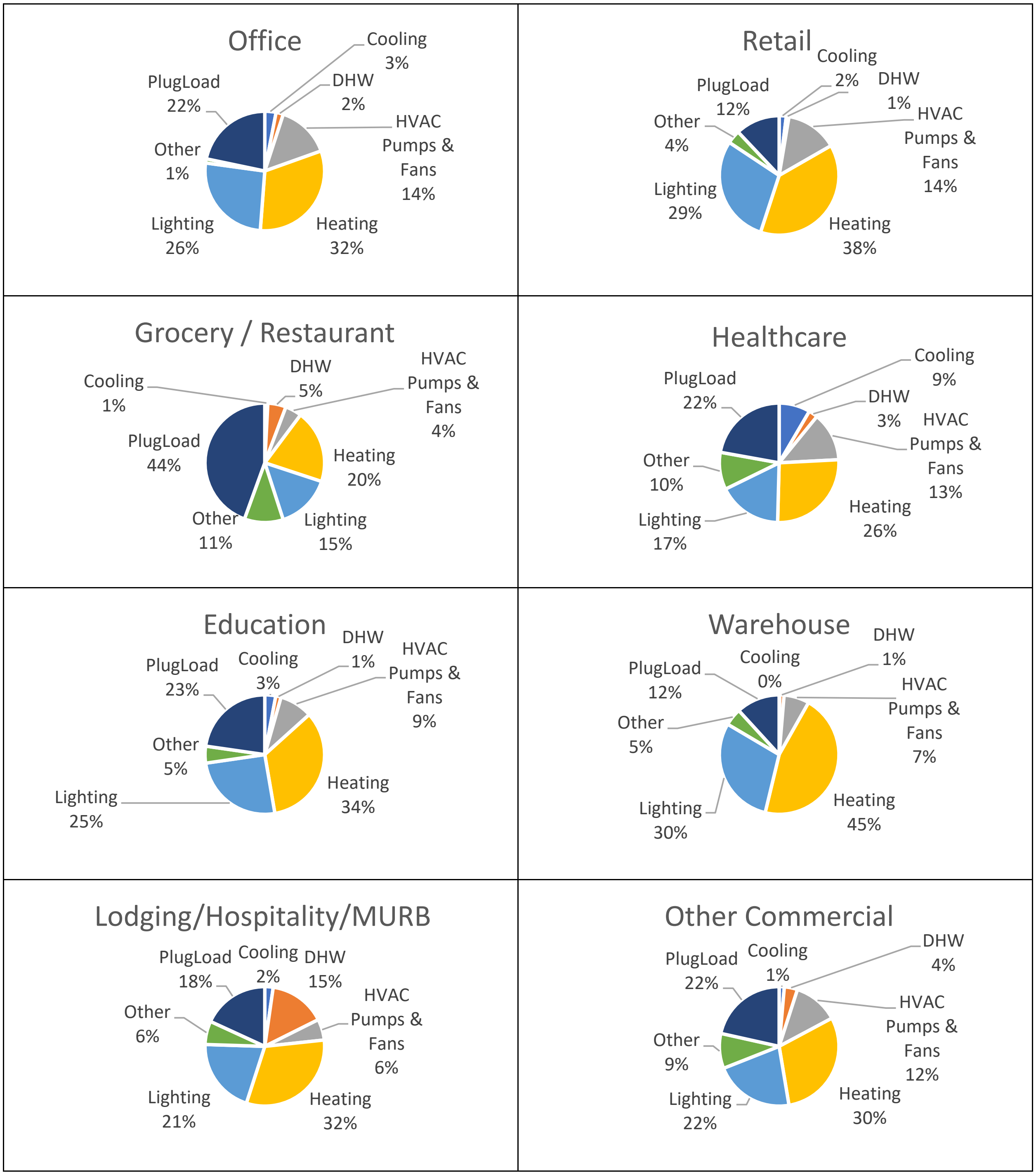
1) They were used to assess standard peak day adjustments for DR addressable peak determination.
2) They were used to develop savings for custom measures, which are expressed as the potential savings as a portion of the associated end-use consumption.
3) They were used to benchmark savings when calibrating the model.
4) They were used to develop winter / summer, on and off-peak savings ratios to apply to seasonal avoided costs in the models.

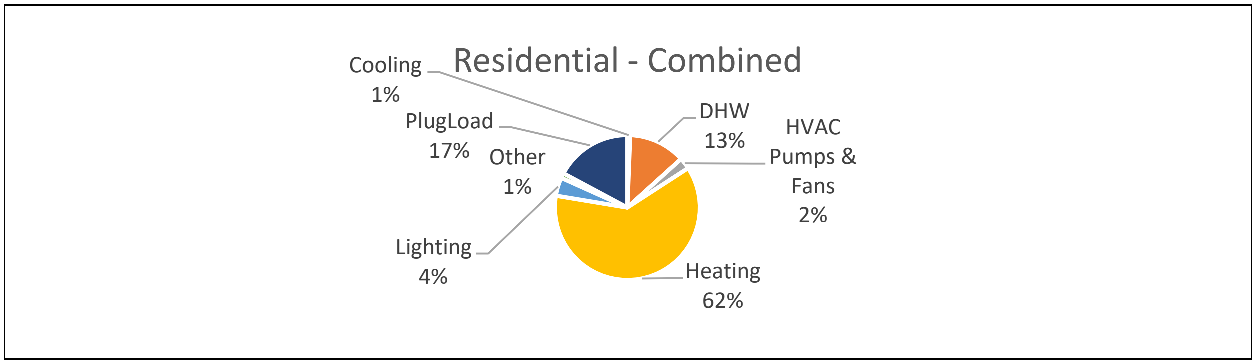
The end-use load curves were developed from the following sources:

- US Department of Energy (US DOE) published load curves, taken from buildings in comparable climate zones to the Newfoundland and Labrador climate zones, and adjusted to account for heating energy source.
- Engineered load profiles and Dunsky's in-house developed sample consumption profiles.
- Data from the "Newfoundland and Labrador conservation and demand management potential study: 2015".

Table E - 33 below presents the end-use consumption for each segment developed from the above sources.

Table E - 33: Annual Consumption: Segment and End-Use Breakdown





In Newfoundland and Labrador, the Industrial sector is split into four segments: fisheries, manufacturing, small/medium industrial and large industrial. Each segment's consumption was grouped into one industrial end-use ("Industrial"), as seen in **Figure E - 5**. NL Utilities provided Dunsky with data for isolated communities with and without fisheries. Based on this information, data about annual fishery consumption was extracted. Furthermore, NL Utilities also provided large industrial load curves (such as IOC consumption). The last two industrial segments: Manufacturing and Small/Medium Industrials were evaluated using Dunsky's internal datasets. Using the assumptions that commercial and residential buildings are similar in both Labrador and Newfoundland, the same end-use breakdown was scaled to LAB consumption.

Using this annual breakdown and an annual (hourly – 8670 hours) building energy consumption simulation from the US DOE (*Commercial Reference Buildings & Building America House Simulation Protocols*) allowed for the recreation of the end-use breakdown for a standard peak day. The figure below presents the energy and sector breakdown for IIC and LAB systems.

Figure E - 4: IIC Standard peak day – Sector breakdown

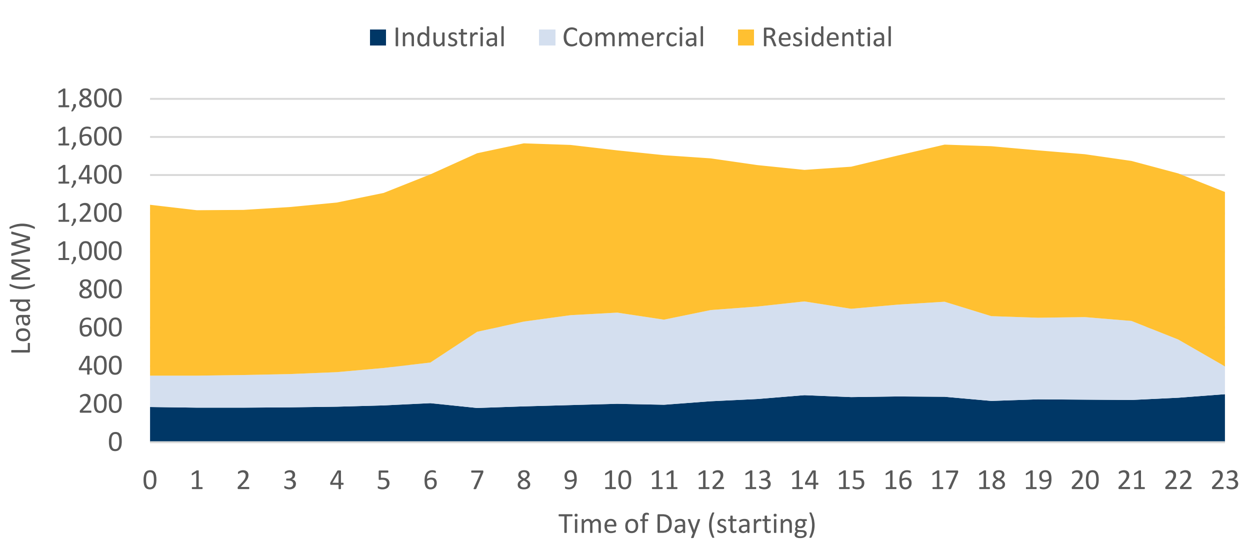


Figure E - 5: IIC Standard peak day – End-use breakdown

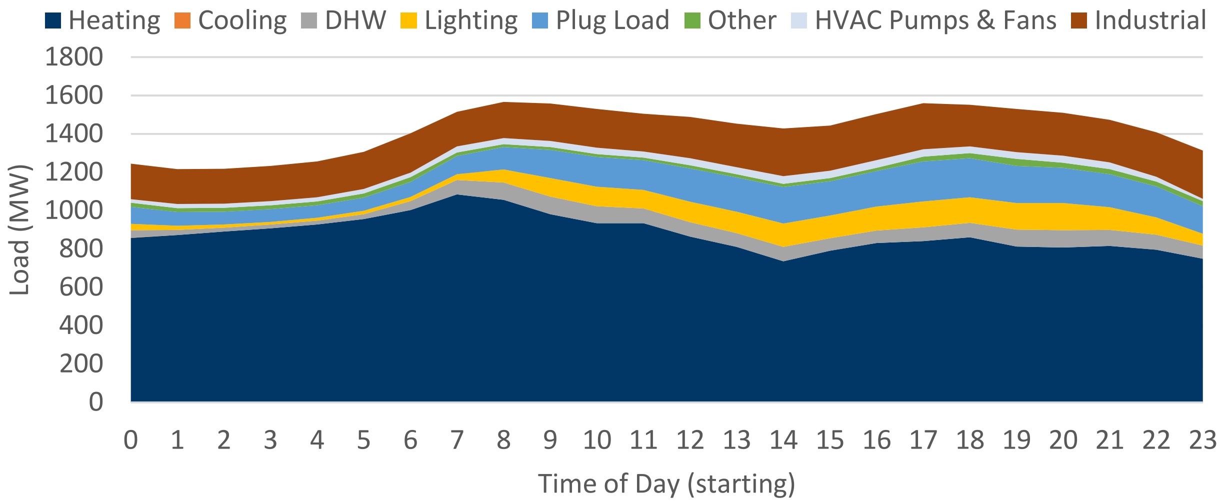


Figure E - 6: LAB Standard peak day – Sector breakdown

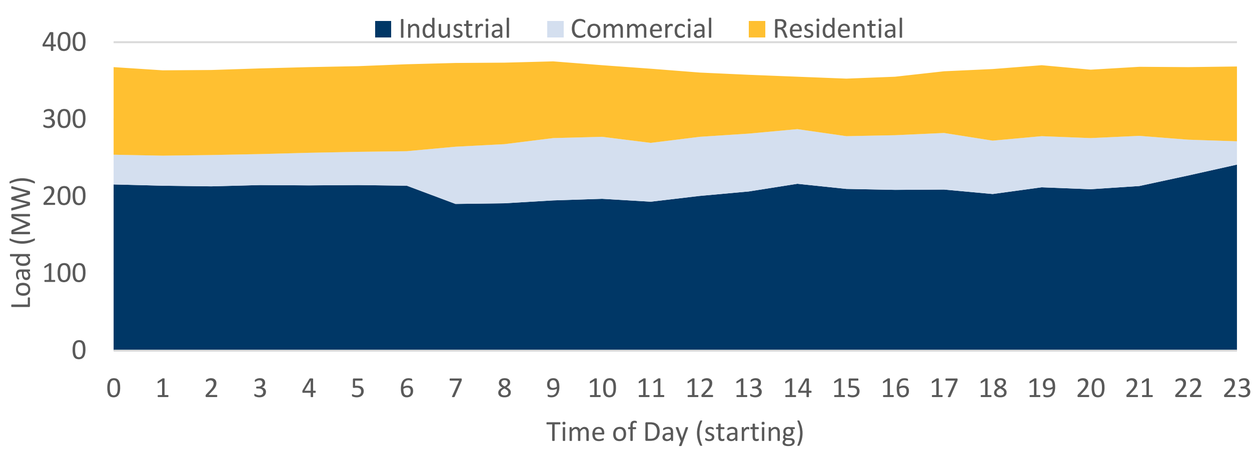
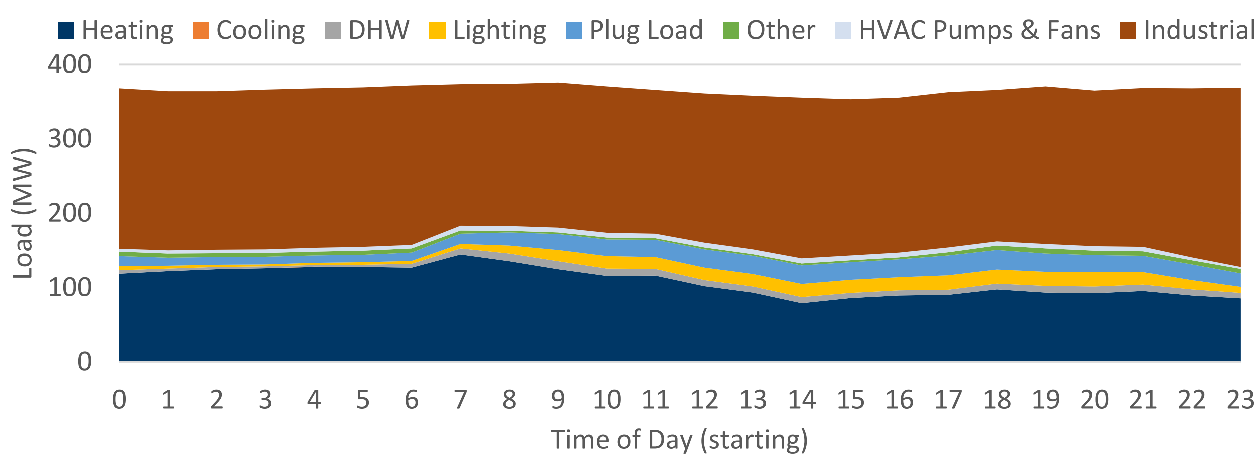


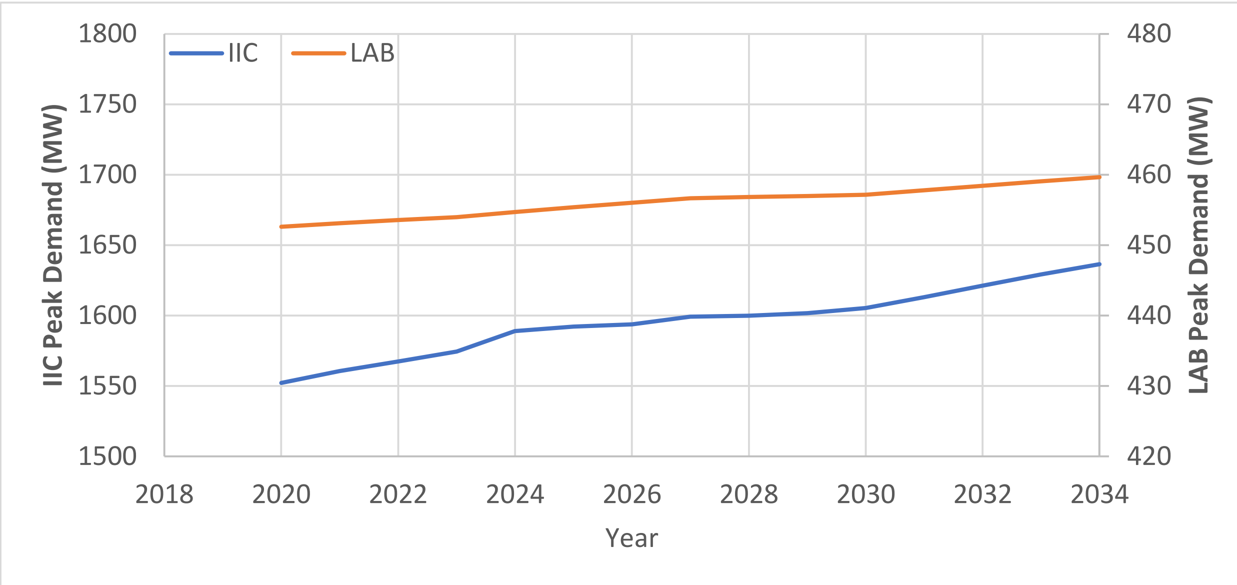
Figure E - 7: LAB Standard peak day – End-use breakdown



FUTURE IMPACTS

The standard peak day was forecasted using the same peak demand forecast as the rest of the potential study. Since no information was available for LAB system, the same growth factors were used for industrial and non-industrial sectors.

Figure E - 8: Newfoundland and Labrador's load forecasting (before EE)



Furthermore, final energy efficiency results from the Lower scenario with mid-rates were combined with the forecast in order to have a better grasp at the future load shape.

Table E - 34: Impact of EE Measures on Demand Response

System	EE impact on Peak-to-average difference (2034)[30]	Peak reduction (2034)	Average hourly EE impact (2034)
IIC	+ 1.6 MW	47 MW	47 MW
LAB	+ 0.6 MW	13 MW	14 MW

[30] Impact of energy efficiency measures on peak to average value. Peak to average is presented, for each system, in the main report. It is a measure of the load curve shape, with lower peak-to-average ratios representing flat load curves, and high ratios representing choppy or high-amplitude peaks.

MEASURES

To assess the DR potential in Newfoundland & Labrador, Dunsky characterized over 25 specific demand reducing measures, based on commonly applied approaches in DR programs across North America, and emerging opportunities such as battery storage. As defined in Appendix B, the measures are covering all customer segments and can be categorized into two groups: Type 1 (constrained by the addressable peak) and type 2 (unconstrained by the addressable peak). Measures of all types have the following key metrics:

- Load shape of the measure
- Constraints
- Measure Effective Useful Life (EUL)
- Costs

Dunsky applied our existing library of applicable DR measure characterizations and adjusted them to reflect end-use energy use profiles in Newfoundland and Labrador's climate. **Table E - 35** and **Table E - 36** provide an overview of each measure characterization and approach.

Table E - 35: Residential Demand Response Measures

MEASURE BY END USE	DEMAND RESPONSE STRATEGY	EUL	MARKET SIZE	INITIAL MEASURE COST	PACT	ADOPTION LIMIT
Appliances						
Clothes Washer	Conventional residential clothes washer enabled for Direct Load Control (DLC) by utility	14	Number of clothes washers in the province	Zigbee relay costs (or smart devices)	Fail	Not cost-effective
Clothes Dryer	Conventional residential clothes dryer enabled for DLC by utility	11	Number of clothes dryers in the province	Zigbee relay costs (or smart devices)	Pass	Potential filled by more cost-effective measure
Dishwasher	Conventional residential dishwasher enabled for DLC by utility	11	Number of dishwashers in the province	Zigbee relay costs (or smart devices)	Fail	Not cost-effective
Hot Tubs / Spas	Conventional residential spa enabled for DLC by utility	10	3% of households	Zigbee relay costs	Pass	Potential filled by more cost-effective measure
Refrigerator	Conventional residential refrigerator enabled for DLC by utility	14	Number of residential refrigerators in the province	Zigbee smart plug and hub costs	Fail	Not cost-effective
Hot Water						
Resistance Storage Water Heater	Conventional residential electric water heater enabled for DLC by utility	10	Residential electric water heater (excl. heat pump water heater)	A fast DR enabled control device	Pass	Potential filled by more cost-effective measure
Heat Pump Storage Water Heater	Residential heat-pump water heater enabled for DLC by utility	15	Residential heat pump water heater	A fast DR enabled control device	Fail	Not cost-effective
HVAC						
Space Setpoint Control	Existing Programmable/Manual thermostat enabled for DLC by utility	20	All electric heated households with programmable or manual thermostat	Installation of a communication device or WiFi thermostat	Pass	Utility-wide load curve constraints
Dual Fuel Measure (Fuel switching at peak)	Fuel switching during peak events	20	All electric heated households with central furnace or boiler	Cost of the full equipment ($9,000)	Pass	Utility-wide load curve constraints

MEASURE BY END USE	DEMAND RESPONSE STRATEGY	EUL	MARKET SIZE	INITIAL MEASURE COST	PACT	ADOPTION LIMIT
Other						
Electrical Vehicle (EV)	EVs are charged through charging stations (assumed level 2 AC). The measure is applied to existing EV owners who plug for a long period of time. Therefore, the scope is limited to homes.	13	Number of EVs in NL x % charged at home	Incremental cost of a smart charger	Fail	Not cost-effective[31]
Battery Energy Storage	Installation of a Powerwall in household for DR	10	All households	Full cost of the battery	Fail	Not cost-effective
Time-of-Use (TOU)	Implementation of a TOU Rates Program combined with a pricing signal at the peak moment to increase the program efficiency	1	All households	None	Fail[32]	n/a[33]

[31] Residential EV measure is not cost-effective based on the current adoption projections applied by the utilities, as they are insufficient to create an evening peak that exceeds the morning peak. Under the EV penetration levels assessed in Chapter 6 of this study, EV smart charging may become cost-effective.

[32] First year PACT. Does not include negative impact from lost industrial curtailment potential.

[33] TOU rates is a curve shaping mechanism. Therefore, it is applied first to the entire applicable market and does not enter into competition with other measures.

Table E - 36: Non-Residential Demand Response Measures

MEASURE BY END USE	DEMAND RESPONSE STRATEGY	EUL	MARKET SIZE	INITIAL MEASURE COST	PACT	ADOPTION LIMIT
Appliances						
Commercial Refrigeration	Commercial refrigeration load shedding through existing BAS	14	Refrigeration load per building x number of buildings (Grocery only)	None	Pass	Potential filled by more cost-effective measure
Hot Water						
Resistance Storage Water Heater	Existing electric water heater enabled for DR	10	C&I electric water heaters (excl. heat pump water heater)	Varies by segments and covers the costs of enabling the system	Fail	Not cost-effective
HVAC						
Space Setpoint Control	Controlling the space setpoint through an existing BAS or Prog/Manual thermostat during peak events	1	All electric heated C&I buildings	None	Pass	Potential filled by more cost-effective measure
Heating Pump Flow Rate Adjustment	Modulation of the heating pump flow rate during peak events	1	Large office, hospital and education buildings (sectors where hydronic heating is more prevalent)	Varies by segment and covers the installation of VFDs on pumps	Fail	Not cost-effective
Interruption of Humidification	Shutting off the electric humidifier in the model, through a schedule, during peak events *Measure divided in two: one at no cost applicable to building with BAS or done manually and one for buildings without a BAS where controls are installed as part of the measure.*	1	C&I buildings with electric humidification	None if through BAS or manual. Varies by building size for the automated measures without BAS.	Pass	Potential filled by more cost-effective measure
Reduction of Fresh Air Flow	Closing the outdoor air dampers during peak events *Measure divided in two: one at no cost applicable to building with BAS or done manually and one for buildings without a BAS where controls are installed as part of the measure.*	1	All electric heated C&I buildings.	None if through BAS or manual. Varies by building size for the automated measures without BAS.	Pass	Potential filled by more cost-effective measure
Reduction of Ventilation Flow	Reducing the static pressure set point for variable air volume (VAV) systems during peak events which results in a fan speed reduction	1	Large office, hospital and education buildings (sectors where VAV are more prevalent)	None	Pass	Potential filled by more cost-effective measure

MEASURE BY END USE	DEMAND RESPONSE STRATEGY	EUL	MARKET SIZE	INITIAL MEASURE COST	PACT	ADOPTION LIMIT
Dual Fuel Measure	Fuel switching during peak events	10	All electric heated C&I buildings with central heating system	Varies by segment and covers the installation of a fuel-fired boiler/furnace	Pass	Utility-wide load curve constraints
Lighting						
Lighting Control (Manual or BAS)	Turning off some of the fixtures using the existing BAS system or manually	1	All fuel heated C&I buildings	None	Pass	Potential filled by more cost-effective measure
Lighting Control	Installation of an addressable dimmable system to reduce level by 30% during peak events	1	All fuel heated C&I buildings	Varies by building size for installing a modulating system	Fail	Not cost-effective
Other						
Electrical Vehicle (EV)	EVs are charged through charging stations (assumed level 2 AC). The measure is applied to existing EV owners who plug for a long period of time. Therefore, the scope is limited to offices.	13	Number of EVs in NL x % charged at the office	Incremental cost of a smart charger	Pass	Potential filled by more cost-effective measure
Backup Generation at Peak Hours	Existing back-up generator enabled for DR	30	IIC: NL CEUS data LAB: 8% of all C&I buildings, based on EIA's CBECs data.	Varies by segment and covers the costs of enabling system	Pass	No more potential
Battery Energy Storage	Installation of a Powerwall/Powerpack enabled for DR	10	All C&I buildings	Full cost of the battery	Fail	Not cost-effective
Industrial Interruptible Load	Load shifting to weekend, via expansion of existing programs or interruptible rates.	1	Large industrial customers not currently enrolled in interruptible rates 7-8% of all Small & Med. Industrials, based on Dunsky internal data from Atlantic Canada	None	Pass	Market constraints
Time-of-Use (TOU) Rates	Implementation of a TOU Rates Program combined with a pricing signal at the peak moment to increase the program efficiency	1	All commercial and institutional buildings	None	Fail[34]	n/a[35]

[34] First year PACT. Does not include negative impact from lost industrial curtailment potential.

[35] TOU rates is a curve shaping mechanism. Therefore, it is applied first to the entire applicable market and does not enter into competition with other measures.

EXISTING CONSERVATION VOLTAGE REDUCTION

NF Power has the possibility to apply 30 MW CVR as a DR measure to reduce load demand. To translate these demand savings to true savings Dunsky used CVR factor for winter load described in the table below. CVR factors for each sector were scaled respectively to the weight of that sector in the peak demand of the IIC system.

Table E - 37: CVR factor per load type[36]

Type	Summer CVR	Winter CVR
Residential, all electric	0.67	0.06
Residential, not all electric	0.67	0.12
Commercial	0.97	0.80
Small Industries	0.10	0.10
Overall	0.61	0.27

DYNAMIC RATES

Dynamic rates impacts were assessed using a peak to off-peak ratio.

Figure E - 9 presents this relationship that was established in a meta-analysis of TOU and dynamic rates by the Brattle Group.[37] This relationship is used to estimate peak savings and the energy shifted outside of the peak hours. Finally, based on Ontario's TOU roll-out few to no energy conservation was reported when implementing TOU rates. For this reason, the study assumes a small 2% savings on the energy displaced over peak hours. Due to the higher response of customers to CPP rates (as it is only a few times per year), savings were assumed to be 20% of the energy displaced during peak hours.

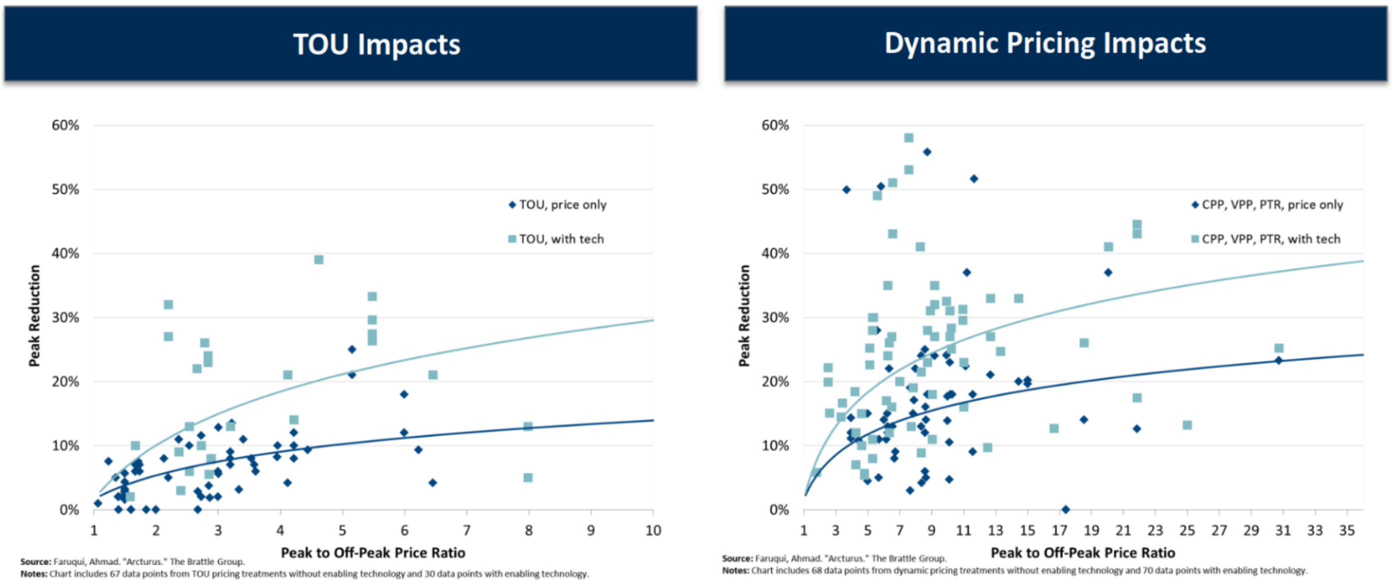
[36] CVR factors were assessed from "Measuring the efficiency of voltage reduction at Hydro-Québec distribution", S. Lefebvre ; G. Gaba ; A-O. Ba ; D. Asber ; A. Ricard ; C. Perreault ; D. Chartrand. IEEE, 2008.

[37] Peak reduction from dynamic rates was assessed from "Arcturus: International Evidence on Dynamic Pricing", A. Faruqui and S. Sergici. 2013.

AMI

An estimate for AMI rollout was also developed to assess cost effectiveness. Using customer data provided by NL Utilities, it was estimated that roughly 275,000 meters would be required to completely convert the actual customers. With an EUL of 15 years, and costs based on NB Power estimates[38] and pro-rated to NL, Dunsky estimates a full-scale AMI deployment would cost \$85-\$105M.

Figure E - 9: Dynamic Rate Peak Reduction



[38] Costs taken from "Decision – Matter No.375", New Brunswick Energy and Utilities Board, 2018

FUEL SWITCHING

While the fuel switching analysis uses many of the same inputs and assumptions as the CDM Potential analysis, there are multiple distinctive inputs and assumptions due to the unique nature of the analysis. The following section outlines these inputs and assumptions where they differ from the CDM Potential analysis.

INPUTS

Fuel oil and woody biomass costs

To determine the customer economics of switching from oil and wood-based heating systems to electric-based heating systems, the model requires inputs for retail rates for oil and wood heating fuels.

Customer heating oil costs are assumed to be equal to the maximum retail heating fuel cost as set by the NL Board of Commissioners of Public Utilities.[39] Historical maximum prices were analyzed and future oil costs were concluded to increase nominally over time in the absence of intervening policies such as carbon pricing.

Woody biomass costs are based on simple average cost estimates for wood pellets and green wood chips based on price data from Argus Media and J.D. Irving, respectively.[40] Future woody biomass costs are assumed to slightly increase based on annual growth factors taken from a report on energy supply costs in New England.[41]

Carbon pricing

To test fuel switching sensitivity to a carbon price, a carbon-adder is added to fuel oil prices for sensitivity analyses. Woody biomass fuels are excluded from carbon pricing. The sensitivity analyses test the impact of carbon pricing under the federal government's carbon pricing backstop, which starts at $20 in 2019 and increases to $50 in 2022, and under a significantly higher carbon price set at the Environment and Climate Change Canada's Social Cost of Greenhouse Gas Estimates in 2020 at the 95th percentile, which is

[39] Newfoundland and Labrador Board of Commissioners of Public Utilities. "Petroleum Pricing Regulated Fuel Prices". Access at: http://www.pub.nf.ca/ppoprices.htm

[40] Argus Media. "Argus Biomass Markets". Accessed at: https://www.argusmedia.com/en/bioenergy/argus-biomass-markets
Irving Woodlands Division. "Wood Prices". Accessed at: https://irvingwoodlands.com/jdi-woodlands-wood-producers-wood-prices.aspx

[41] Synapse Energy Economics. "Avoided Energy Supply Components in New England: 2018 Report". Access at: https://www.synapse-energy.com/sites/default/files/AESC-2018-17-080.pdf

approximately $213.36 in current dollars.[42] **Table E - 38** shows these carbon prices in dollar per litre of fuel oil equivalents.

Table E - 38: Fuel oil carbon-adders

	Federal backstop		Social cost of carbon	
Year	$ per tonne	$ per litre fuel oil equivalent	$ per tonne	$ per litre fuel oil equivalent
2020	$30	$0.0821	$213	$0.58
2025	$50	$0.1369	$239	$0.65
2030	$50	$0.1369	$264	$0.72
2035	$50	$0.1369	$290	$0.79

ASSUMPTIONS

Measure characterization

The heat pump components of fuel switching measures were generally adapted from the most similar measures characterized as part of the CDM Potential analysis. The analysis assumes customers adopt heat pumps that conform to the U.S. Department of Energy's 2023 efficiency standards for air source heat pumps and ductless mini-split heat pumps, which NRCan is anticipated to align with in the future. The efficiency of base technologies (e.g. combustible fuel systems) are assumed to be at federal standards or average installed efficiency, where appropriate. Incremental costs are the additional cost of installing a heat pump technology instead of a combustible-fuel based technology for replace on burnout (ROB) measures. For additional (ADD) measures, the incremental cost is the total cost of the heat pump technology.

Table E - 39 and **Table E - 40** list the incremental cost and efficiency assumptions for each measure.

Table E - 39: Fuel switching: residential measure assumptions

Measure	Measure Type	Base Unit	Incremental Costs	Heat Pump Efficiency	Base technology efficiency
Oil Furnace to ASHP	ROB	per unit	$1,600	7.65 (HSPF)	0.83 (COP)
Oil Furnace to DMSHP	ADD	per unit	$5,250	7.65 (HSPF)	0.83 (COP)
Oil Boiler to DMSHP	ADD	per unit	$5,250	7.65 (HSPF)	0.84 (COP)
Wood Stove to ASHP	ROB	per unit	$5,400	7.65 (HSPF)	0.66 (COP)

[42] Technical Update to Environment and Climate Change Canada's Social Cost of Greenhouse Gas Estimates (March 2016). Accessed at: https://ec.gc.ca/cc/default.asp?lang=En&n=BE705779-1#SCC-Sec1

Wood Stove to DMSHP	ADD	per unit	$5,250	7.65 (HSPF)	0.53 (COP)
Electric Resistance to DMSHP	ADD	per unit	$5,250	7.65 (HSPF)	1 (COP)
Oil Hot Water to Heat Pump Hot Water Heater	ROB	per unit	$3,300	2 (EF)	0.6 (EF)

Table E - 40: Fuel switching: commercial measure assumptions

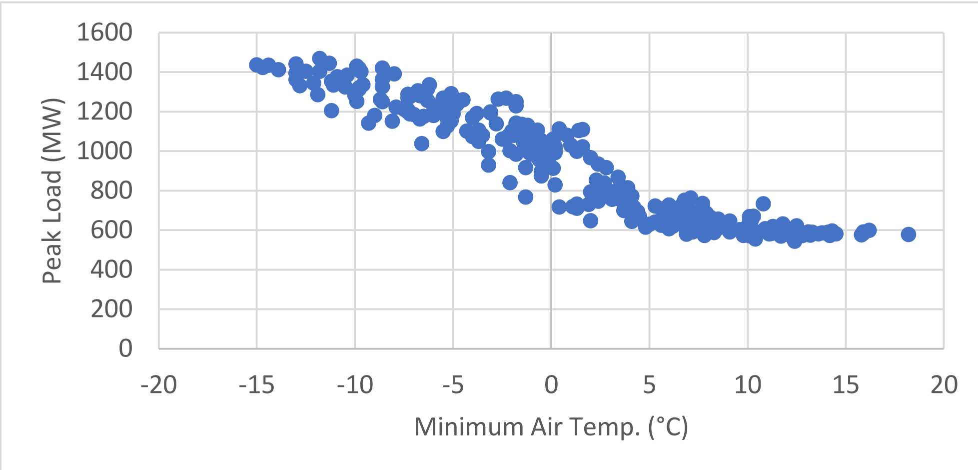
Measure	Measure Type	Base Unit	Incremental Costs	Heat Pump Efficiency	Base technology efficiency
Oil Furnace to ASHP	ROB	per ton	$2,200 to $2,600	7.46 (HSPF)	0.78 (COP)
Oil Furnace to DMSHP	ADD	per ton	$3,600	7.65 (HSPF)	0.78 (COP)
Oil Boiler to DMSHP	ADD	per ton	$3,600	7.65 (HSPF)	0.84 (COP)
Oil Hot Water to Heat Pump Hot Water Heater	ROB	per unit	$3,900 to $5,000	2.2 (EF)	0.6 (EF)

The demand impacts of heat pumps are determined by assuming these systems will be operational at peak hours albeit at a reduced efficiency and capacity. Since peak demand hours tend to occur when minimum outside temperatures are between -10°C and -15°C (see **Figure E - 10**), heat pumps are assumed to have a coefficient of performance (COP) of 1.75 during peak hours.[43] Additionally, heat pumps are assumed to operate at a de-rated capacity of approximately 63%.[44] However, not all households that install heat pumps are expected to run them during peak hours due to various factors such as control settings and other behavioral reasons. Since no NL specific study is available, professional judgement was applied in the analysis to assume 85% of heat pumps will be operating during peak hours for an effective capacity de-rate of 53.5%.

[43] Minnesota Commerce Department. "Cold Climate Air Source Heat Pump." (2017). Accessed at: https://www.mncee.org/MNCEE/media/PDFs/86417-Cold-Climate-Air-Source-Heat-Pump-(CARD-Final-Report-2018).pdf

[44] Minnesota Commerce Department. "Cold Climate Air Source Heat Pump." (2017). Accessed at: https://www.mncee.org/MNCEE/media/PDFs/86417-Cold-Climate-Air-Source-Heat-Pump-(CARD-Final-Report-2018).pdf

Figure E - 10: IIC Peak Load Versus Minimum Air Temperature



For the combustible fuel components of the fuel switching measures, units are assumed to conform to federal baseline efficiency standards. Energy impacts are determined using algorithms that take into consideration system efficiencies, sizes and annual heating load. Incremental costs are modified to account for differences in equipment costs as well as ancillary costs such as oil tank removal and backup heating system costs.

Since heat pumps can provide both heating and cooling energy, this additional benefit (relative to combustible fuel systems that only provide heating energy) is accounted for by adding a non-energy benefit to measures that provide cooling services. Additionally, this non-energy benefit ensures that the cost of cooling related energy does not reduce customer economics. For residential systems, the benefit is equivalent to approximately 2 times the annual cost of energy (kWh) consumed to provide cooling. Since there are few cooling hours in Newfoundland, this non-energy benefit is between \$30 and \$80 per year. For commercial systems, the benefit is equivalent to approximately 1.25 times the annual cost of energy consumed to provide cooling, plus 50% of the incremental cost of the heat pump system. Non-energy benefits for the commercial sector account for incremental system costs due to the higher likelihood the commercial customer would purchase an air conditioning system in the absence of the heat pump system.

Heat pump markets

The technical potential for central heat pumps in residential households is assumed to be one per household. For ductless mini-split heat pumps, customers are assumed to be able to adopt more than one per household. Based on the average size of installed DMSHP in each residential segment, this translates a maximum of roughly two 1.5-ton DMSHP per single detached household as shown in **Table E - 41**. Offsetting 100% of annual heating load is not assumed to account for distribution and behaviour effects.

Table E - 41: Maximum Number of DMSHP per Household

Segment	Max number of DMSHP per household
Single detached	2.0
Attached	1.5
Apartment	1.3

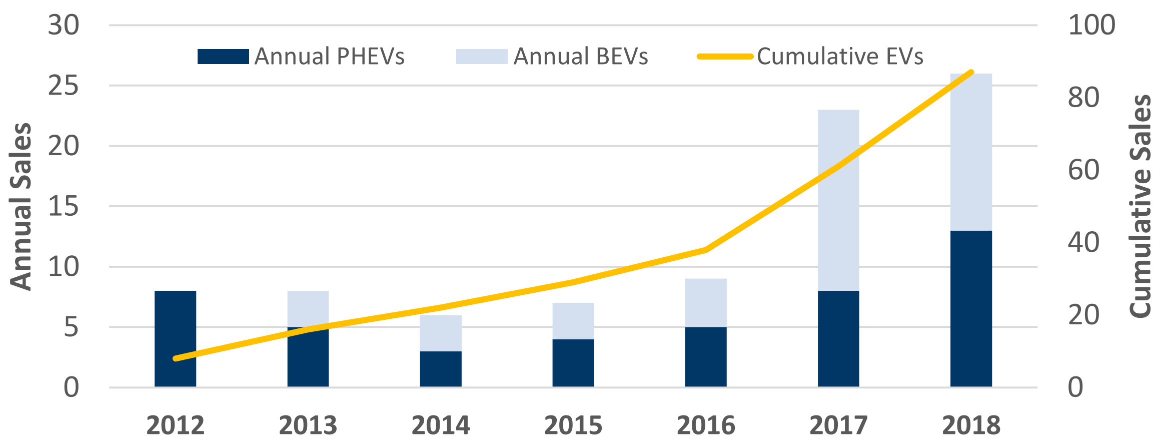
ELECTRIC VEHICLES

MODEL INPUTS

HISTORICAL EV ADOPTION

Historical EV adoption data was determined using a consolidation of data from the Utilities, ServiceNL, and IHS Markit. Approximately 90 EVs are estimated to have been registered in NL by the end of 2018, with a roughly equal split between BEVs and PHEVs.

Figure E - 11. Historic EV Adoption in Newfoundland and Labrador



VEHICLE SALES AND FLEET SIZE

Data on fleet size and annual vehicle sales for Newfoundland and Labrador-specific assumptions were gathered[45] to assess the current composition of vehicle market in the province. Additional assumptions were used to develop estimates of different vehicles classes and the split between personal and commercial sectors. **Table E - 42** show the final assumed market size for the modeled vehicle segments.

Table E - 42: Vehicle Sales and Fleet Size by Vehicle Class and Sector

Segment	Vehicle Class	Fleet Size	Annual Sales
Personal	**Cars**	148,310	11,000
	Trucks	88,480	9,400
	SUVs	39,750	4,200
Commercial	**Cars**	34,300	2,600
	Trucks	19,510	2,100
	SUVs	53,920	5,700
	MDV	17,350	2,000
	HDV	4,900	300

[45] Natural Resources Canada (NRCan). Comprehensive Energy Use Database – Transportation Sector

	Bus	1,370	100

VEHICLE ARCHETYPES

For each vehicle class and drivetrain combination, a representative vehicle archetype was defined. Light-duty vehicle archetypes are common between personal and commercial use and are presented in **Table E - 43**. Medium-duty vehicle, heavy-duty vehicle, and bus archetypes are presented in **Table E - 44**. For each vehicle, the input characteristics were used to develop a bottom-up vehicle cost that accounts for baseline vehicle cost, ICE and electric powertrain costs and battery costs. Additionally, data on O&M costs, average fuel efficiency, driving distance and assumed lifetime were used to calculate the vehicle's Total Cost of Ownership (TCO). Additionally, for BEVs and PHEVs, the cost of a home or depot charger was also added to the vehicle cost.

Table E - 43: Light-Duty Vehicle Model Inputs

	Car			SUV			Truck		
	BEV	**PHEV**	**ICE**	**BEV**	**PHEV**	**ICE**	**BEV**	**PHEV**	**ICE**
Battery size (kWh)	58	12	N/A	72	14	N/A	80	16	N/A
Electric powertrain output (kW)	150	135	N/A	200	180	N/A	200	180	N/A
ICE powertrain output (kW)	N/A	75	150	N/A	100	200	N/A	100	200
Vehicle efficiency electric (kWh/km)	0.18	0.18	N/A	0.23	0.23	N/A	0.25	0.25	N/A
Vehicle efficiency ICE (L/km)	N/A	0.10	0.10	N/A	0.11	0.11	N/A	0.13	0.13
Vehicle Utilization[46]	**Personal LDV:** 20,000 km per year, 5-year lifetime **Commercial LDV:** 30,000 km per year, 4-year lifetime								
% Vehicle electric drive	100%	50%	N/A	100%	50%	N/A	100%	50%	N/A
Annual Non-Fuel O&M Costs	$20	$70	$140	$20	$70	$140	$20	$70	$140
Home charger power (kW)	7	7	N/A	7	7	N/A	7	7	N/A

[46] The vehicle utilization represents the distance driven and duration of time that is assumed to be taken into consideration when calculating the vehicle's total cost of ownership (TCO), rather than the actual expected life of the vehicle.

	Car			SUV			Truck		
	BEV	**PHEV**	**ICE**	**BEV**	**PHEV**	**ICE**	**BEV**	**PHEV**	**ICE**
Annual Energy Consumption (kWh)[47]	3,500 – 5,250	1,750 – 2,625	N/A	4,400 - 6,600	2,220 – 3,300	N/A	2,450 – 3,700	4,900 – 7,400	N/A
Vehicle Purchase Cost (2019) – Baseline Scenario	$38,300	$31,300	$28,300	$53,300	$44,900	$41,100	$50,100	$40,200	$36,100
Home/Depot Charger Cost and Installation	$1000	$1000	N/A	$1000	$1000	N/A	$1000	$1000	N/A

[47] Lower and upper range represent the annual consumption of a personal LDV and a commercial LDV respectively.

Table E - 44: Medium-Duty Vehicle, Heavy-Duty Vehicle, and Bus Vehicle Model Inputs

	Medium-Duty Vehicle		Heavy-Duty Vehicle		Bus	
	BEV	ICE	BEV	ICE	BEV	ICE
Battery size (kWh)	100	N/A	750	N/A	270	N/A
Powertrain output (kW)	175	175	540	540	300	300
Vehicle efficiency electric (kWh/km)	0.9	N/A	1.3	N/A	0.9	N/A
Vehicle efficiency ICE (L/km)	N/A	0.3	N/A	0.4	N/A	0.6
Vehicle Utilization[46]	25,000 km per year 12-year lifetime		130,000 km per year 12-year lifetime		65,000 km per year 12-year lifetime	
Annual O&M costs	$940	$1,880	$4,880	$9,760	$35,100	$49,500
Depot charger power (kW)[48]	20 kW	N/A	150 (*2020*) – 2000 (*2029*)	N/A	50 kW	N/A
Annual Energy Consumption (kWh)	22,500	N/A	162,500	N/A	81,000	N/A
Vehicle Purchase Cost (2019) – Baseline Scenario	$140,200	$88,700	$568,600	$167,600	$368,400	$232,000
Depot Charger Cost and Installation	$15,000	N/A	$75,000	N/A	$35,000	N/A

NON-VEHICLE ASSUMPTIONS

Additional, non-vehicle assumptions are used in the model to assess barriers associated with both home and public charging. These assumptions are presented in **Table E - 45**.

[48] Assume overnight charging for MDV and bus, and a combination of overnight and on-route fast charging for HDV. It is also assumed that the average power of on-route HDV charging increases overtime, so high and low average power (with year expected) is provided.

Table E - 45: Non-Vehicle Assumptions

General Model Inputs		Province-Wide	Population Clusters[49]
Newfoundland Population		525,000	301,000
Newfoundland Area (km^2)		405,000	357
Newfoundland highway length (km)		2,500	N/A
Housing Composition	**Single Family Homes**	75%	N/A
	Multi-Family Homes	25%	N/A
Home Charging Access	**Single Family Homes**	85%	N/A
	Multi-Family Homes	0%[50]	N/A

SENSITIVITY FACTOR INPUTS

Given uncertainty with respect to the evolution of both local and global factors that are expected to influence EV adoption, a range of values were defined for each factor and sensitivity tests were completed. Local factors that were assessed include electricity rates, fuel prices, and vehicle sales (volumes and vehicle class composition). The results of the sensitivity analyses are provided in the body of the report. The range of values defined for each factor are presented here. The electricity rates used in the sensitivity analysis are the utilities' low, mid and high scenarios; highlighted in the Customer Rates Tables section in Appendix E.

Table E - 46: Gasoline and Diesel Price Assumptions ($/Litre)[51] [52]

	2020	2025	2034
Gasoline			
Low	1.36	1.36	1.50
Mid	1.66	1.62	1.81
High	1.89	1.91	2.12
Diesel			
Low	1.11	1.10	1.23
Mid	1.39	1.35	1.52
High	1.61	1.63	1.82

[49] Population clusters are defined as areas with populations over 1,000 people. There are 28 population clusters in Newfoundland and Labrador based on data from Statistics Canada (2017). *Population and Dwelling Count Highlight Tables, 2016 Census.*

[50] See assumptions for MURB retrofit program scenarios.

[51] National Energy Board (NEB), 2018. Canada's Energy Future 2018 – Macro Indicators.

[52] Low, medium and high cases from indicated source were converted from 2018 dollars to nominal dollars.

Table E - 47: Annual Vehicle Sales Assumptions (Number of Vehicles)

	2020	2025	2034
Car			
Low	9,700	6,760	3,300
Mid	10,000	7,760	4,540
High	10,490	8,890	6,200
SUV			
Low	10,300	12,330	14,380
Mid	10,710	14,170	19,750
High	11,140	16,230	26,950
Truck			
Low	4,600	5,510	6,420
Mid	4,790	6,330	8,820
High	4,980	7,250	12,040

Table E - 48: Battery Cost Assumptions ($/kWh)

	2020	2025	2034
Light-duty vehicles			
Low	202	127	55
Mid	219	169	105
High	230	199	154
Medium-duty vehicles, heavy-duty vehicles, buses[53]			
Low	337	127	55
Mid	366	169	105
High	384	199	154

SCENARIO INPUTS

Scenarios were defined and analyzed to assess the impact of four types of program levers that could be employed by Utilities, governments, and other market actors to influence adoption. The levers included in the assessment were public DCFC charging infrastructure deployment, public L2 charging infrastructure deployment, vehicle purchase incentives, and increasing access to charging in multi-unit residential buildings (MURBs). High and low investment scenarios were assessed for each lever, corresponding to

[53] Based on feedback from manufacturers, a multiplier was added to the battery costs for medium-duty vehicles, heavy-duty vehicles, and buses for years 2020-2024 to account for low production volumes resulting in limited economies of scale and higher battery prices.

investments of $5 million and $20 million, respectively. These scenarios are summarized in **Table E - 49** below.

Table E - 49: Summary of Levers and Investment Scenarios Assessed

Lever	Description	Low Scenario (≈ $5M investment)	High Scenario (≈ $20M investment)
DCFC deployment	**Deployment of Public Direct Current Fast Chargers (DCFC) on highway corridors and in population centres**	**25 Stations (50 ports)**	**100 Stations (200 Ports)**
L2 deployment	Deployment of Public Level 2 (L2) Charging in population centres	125 Stations (500 ports)	500 Stations (2000 ports)
Vehicle Incentives[54]	Rebates to customers to offset a portion of the upfront cost of an EV purchase	$5K incentive for LDVs, 10% incentive for MDV, HDV, Bus	$7.5K incentive for LDVs, 25% incentive for MDV, HDV, Bus

SCENARIO ASSUMPTIONS

For each lever, a baseline scenario was established which assumed no further program action alongside the high and low scenarios. Below, the baseline, high, and low scenario assumptions are presented for each level.

Table E - 50: DCFC Charging Infrastructure Deployment Scenario Assumptions

		2020	2025	2034
Baseline	**Number of Stations**	14	14	14
	Average ports per station	1	1	1
	Average Power (kW)	50	50	50
Low Scenario	**Number of Stations**	16	21	64
	Average ports per station	1	1	2
	Average Power (kW)	53	75	138
High Scenario	**Number of Stations**	22	42	114
	Average ports per station	1	2	2
	Average Power (kW)	60	90	145

[54] Incentives were assumed to step down gradually over time. Detailed assumptions can be found in Appendix C.

Table E - 51: L2 Charging Infrastructure Deployment Scenario Assumptions

		2020	2025	2034
Baseline	**Number of Stations**	44	44	44
	Average ports per station	1.3	1.3	1.3
	Average Power (kW)	7	7	7
Low Scenario	**Number of Stations**	54	94	169
	Average ports per station	1.4	2.7	3.3
	Average Power (kW)	7	7	7
High Scenario	**Number of Stations**	64	244	544
	Average ports per station	1.5	3.2	3.8
	Average Power (kW)	7	7	7

Table E - 52: Purchase Incentive Scenario Assumptions

			2020	2021	2022	2023	2024	2025	2026 - 2034
Baseline	**All Segments**		$0	$0	$0	$0	$0	$0	$0
Low Scenario	**LDV**	**PHEVs**	$2,500	$2,000	$1,600	$1,300	$1,000	$800	$0
		BEVs	$5,000	$4,000	$3,200	$2,600	$2,000	$1,600	$0
	MDV/HDV/Bus[55]	**BEVs**	10%	10%	10%	8%	6%	5%	0%
High Scenario	**LDV**	**PHEVs**	$3,750	$3,750	$3,750	$3,000	$3,000	$2400	$0
		BEVs	$7,500	$7,500	$7,500	$6,000	$6,000	$4,800	$0
	MDV/HDV/Bus	**BEVs**	20%	20%	15%	12%	10%	8%	0%

[55] Incentive amount stated as percentage of vehicle cost

APPENDIX F: DETAILED RESULTS TABLES

BASELINE CONSUMPTION

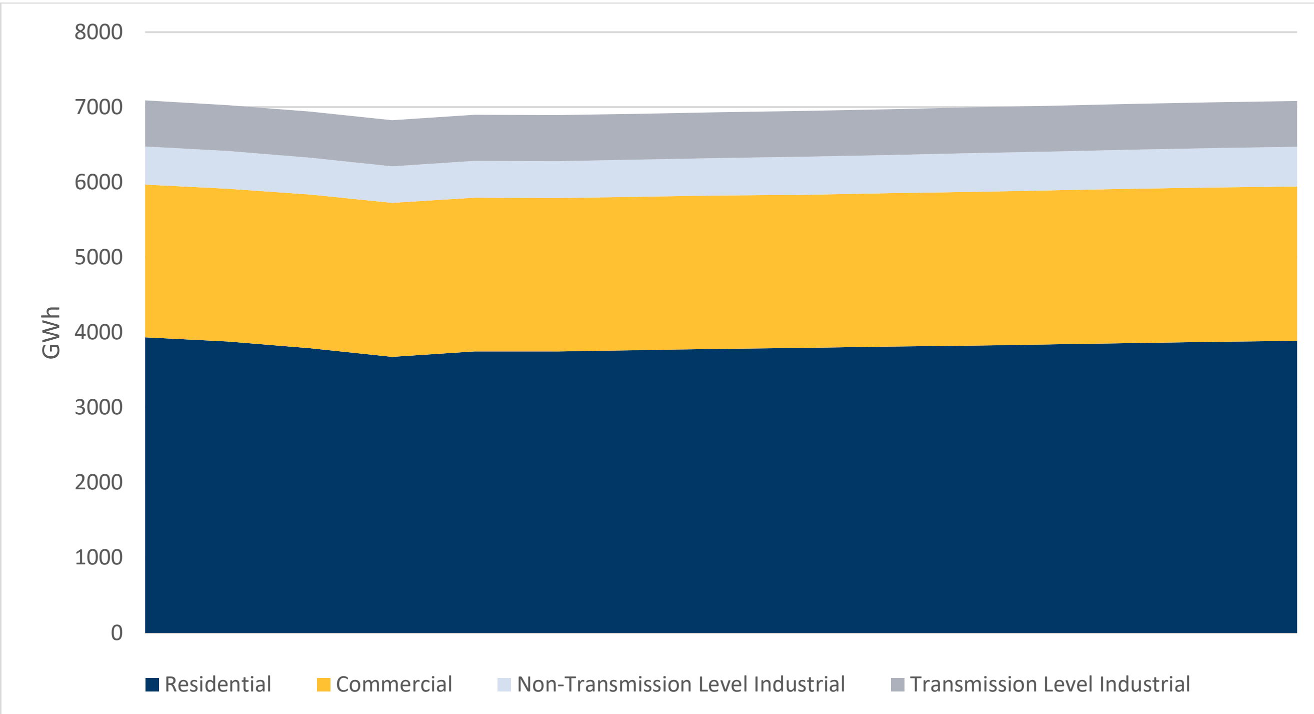
The consumption and demand baseline projection is used to benchmark the effectiveness of an energy efficiency and demand response program portfolio over time. In addition, it is used to generate metrics and perform model calibration.

The consumption and demand baseline were calculated using electric sales forecasts provided by each of the utilities. The consumption forecasts included the effects of naturally occurring savings (e.g. codes and standard changes) as well as projected program savings. Using details provided by the utilities for the project period, the consumption forecast was adjusted to remove the impact of future program savings and naturally occurring savings. Below are more specifics on the process:

- Where applicable, Dunsky removed sectors from the raw forecasts that were not included in the potential model, such as street lighting and electric vehicle charging.
- The following naturally occurring adjustments were explicit in the forecast: lighting and heat pump codes and standards changes. Dunsky removed these standards adjustments from NL Utilities' electricity forecast. If the standards impacted measures in the model, they were considered at the measure level.
- For lighting and heat pump measures, if there was customer adoption due to programs before the codes and standards took effect, the savings for the measures were attributed to the utility through the measure lifetime. For these measures, when replacement occurred, the savings from the replacement was attributed to codes and standards and removed from the baseline.
- The system-wide forecasts for Island Interconnected System were calculated by aggregating the NL Hydro forecasts and the NF Power forecasts for this system. The other systems were calculated using only NL Hydro data.
- Customers under general service rate class 2.4 were considered industrial customers in the baseline. Transmission-level customers were treated separately outside of the model.
- The utilities provided forecasts with implicit utility-based program energy efficiency reductions. Dunsky removed the efficiency program savings from the baseline consumption, using the NL 5-year 2016-2020 Conservation Plan, Table E-1 data.

Additionally, Dunsky calculated an estimate of heating oil consumption in the province using National Energy Board[56] and National Resource Canada[57] data. To calculate the heating oil consumption by system, Dunsky took the total consumption in the province and weighed it by the total electricity consumption in each system.

Figure F- 1: Island Interconnected Electricity Consumption Forecast by Sector



[56]https://apps2.neb-one.gc.ca/dvs/?page=viz2&sector=commercial&unit=petajoules&scenario=reference&sources=solarWindGeothermal,coal,naturalGas,bio,oilProducts,electricity&sourcesInOrder=solarWindGeothermal,coal,naturalGas,bio,oilProducts,electricity&province=NL&dataset=oct2018&language=en

[57]http://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/showTable.cfm?type=CP&sector=com&juris=atl&rn=1&page=0

Figure F- 2: Labrador Interconnected Electricity Consumption Forecast by Sector

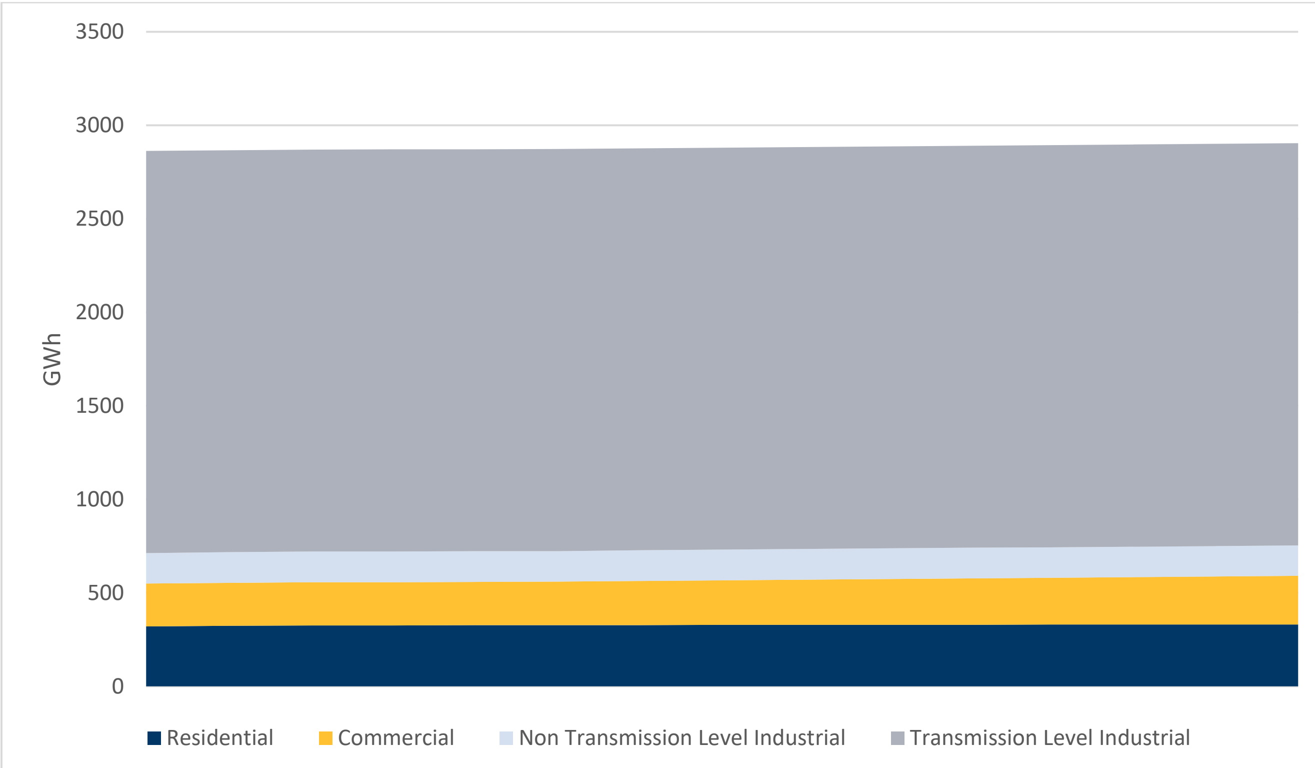
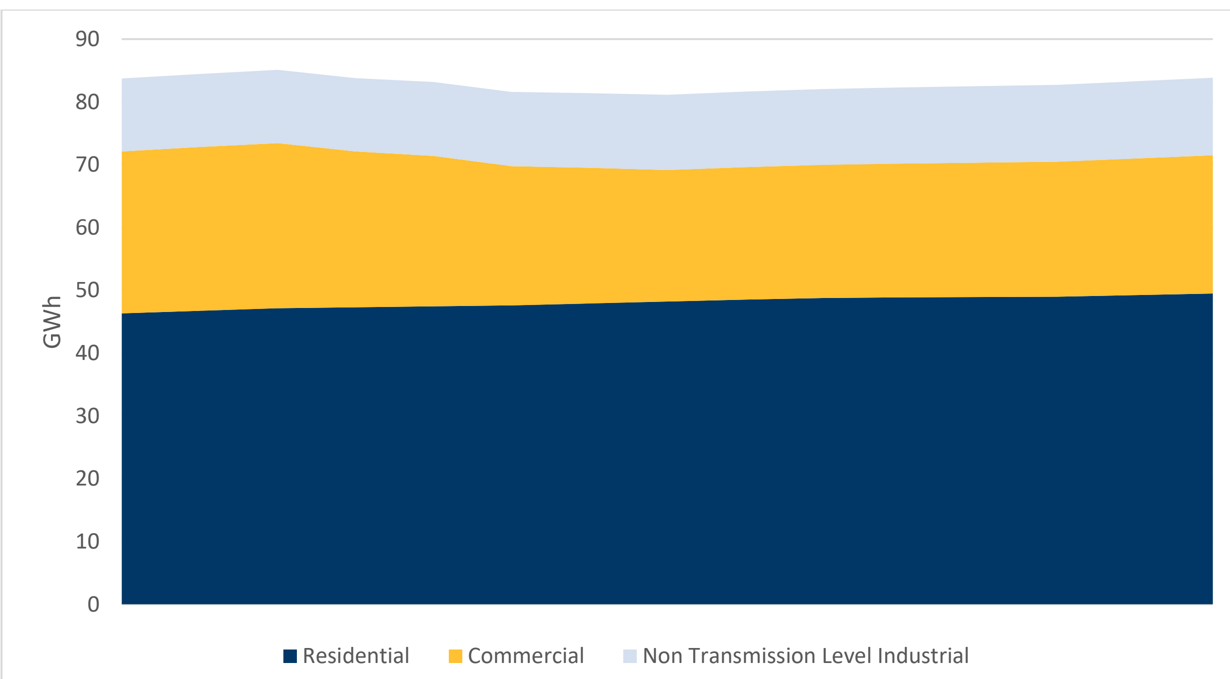


Figure F- 3: Isolated Communities Electricity Consumption Forecast by Sector



DETAILED CUMULATIVE SAVINGS TABLES

This section presents detailed results by sector and end use for each system under the lower, mid, and upper scenarios using the mid- rate case.

LOWER PROGRAM SCENARIO – MID-RATES CASE

Table F- 1: Cumulative Savings by End-Use: IIC System (GWh)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Residential	**19.98**	**29.79**	**40.76**	**50.51**	**60.39**	**66.90**	**73.40**	**79.90**	**86.41**	**92.91**	**96.18**	**99.46**	**102.73**	**106.01**	**109.29**
Appliance	0.17	0.49	1.00	1.76	2.80	3.83	4.87	5.91	6.95	7.98	8.87	9.75	10.63	11.51	12.40
Behavioral	11.22	11.22	11.21	11.21	11.21	11.21	11.21	11.20	11.20	11.20	11.20	11.20	11.19	11.19	11.19
Envelope	3.49	7.46	11.98	17.09	22.72	26.34	29.96	33.58	37.20	40.82	44.46	48.10	51.74	55.37	59.01
Hot Water	1.47	2.93	4.30	5.45	6.26	6.81	7.36	7.91	8.46	9.02	8.32	7.62	6.93	6.23	5.54
HVAC	2.71	5.46	8.18	10.76	13.03	14.36	15.69	17.02	18.35	19.69	19.84	20.00	20.15	20.31	20.46
Lighting	0.91	2.23	4.07	4.22	4.35	4.31	4.27	4.23	4.20	4.16	3.45	2.75	2.04	1.33	0.63
Other	0.00	0.01	0.02	0.03	0.04	0.04	0.04	0.04	0.05	0.05	0.05	0.05	0.05	0.06	0.06
Commercial	**11.78**	**24.68**	**38.69**	**44.40**	**51.58**	**52.69**	**53.81**	**54.92**	**56.03**	**57.14**	**57.54**	**57.93**	**58.33**	**58.72**	**59.11**
Envelope	0.04	0.14	0.33	0.60	0.97	1.18	1.39	1.60	1.82	2.03	2.24	2.46	2.67	2.88	3.10
Hot Water	0.32	0.65	1.02	1.40	1.80	2.02	2.25	2.47	2.69	2.92	2.95	2.98	3.01	3.04	3.07
HVAC	0.39	1.04	1.98	3.15	4.51	5.63	6.75	7.87	8.99	10.11	10.83	11.56	12.29	13.02	13.74
Kitchen	0.03	0.09	0.21	0.40	0.66	0.93	1.19	1.46	1.72	1.99	2.17	2.36	2.54	2.73	2.91
Lighting	10.86	22.27	34.08	36.93	40.61	39.24	37.87	36.50	35.14	33.77	32.44	31.12	29.79	28.47	27.14
Motor/Compressor	0.10	0.33	0.75	1.37	2.20	2.67	3.14	3.62	4.09	4.57	5.04	5.52	5.99	6.47	6.94
Office Equipment	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other	0.03	0.10	0.22	0.37	0.56	0.67	0.78	0.89	1.00	1.11	1.17	1.23	1.29	1.36	1.42
Process	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Refrigeration	0.01	0.05	0.10	0.18	0.28	0.36	0.43	0.51	0.58	0.65	0.68	0.70	0.73	0.76	0.78
Industrial	**0.40**	**1.05**	**1.99**	**3.24**	**4.80**	**5.70**	**6.60**	**7.50**	**8.40**	**9.30**	**9.98**	**10.67**	**11.35**	**12.03**	**12.71**
Envelope	0.01	0.02	0.05	0.09	0.14	0.17	0.20	0.23	0.26	0.29	0.32	0.35	0.38	0.41	0.44
Hot Water	0.06	0.12	0.18	0.24	0.30	0.31	0.33	0.34	0.35	0.37	0.37	0.37	0.37	0.37	0.37
HVAC	0.04	0.11	0.22	0.37	0.55	0.68	0.81	0.94	1.07	1.20	1.28	1.37	1.46	1.55	1.64
Kitchen	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.03
Lighting	0.18	0.36	0.56	0.75	0.95	1.06	1.16	1.27	1.37	1.48	1.43	1.39	1.34	1.29	1.25
Motor/Compressor	0.12	0.41	0.92	1.70	2.71	3.30	3.89	4.47	5.06	5.65	6.23	6.82	7.41	8.00	8.59
Office Equipment	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other	0.01	0.02	0.04	0.07	0.11	0.13	0.16	0.18	0.21	0.23	0.25	0.27	0.29	0.31	0.32
Process	0.00	0.01	0.01	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04
Refrigeration	0.00	0.00	0.00	0.01	0.01	0.01	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03

Table F- 2: Cumulative Savings by End-Use: LAB System (GWh)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Residential	**0.56**	**0.63**	**0.71**	**0.81**	**0.92**	**0.98**	**1.05**	**1.11**	**1.18**	**1.24**	**1.30**	**1.36**	**1.41**	**1.47**	**1.53**
Appliance	0.00	0.00	0.01	0.01	0.02	0.02	0.03	0.03	0.04	0.05	0.05	0.06	0.06	0.07	0.08
Behavioral	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51
Envelope	0.01	0.03	0.07	0.11	0.16	0.19	0.22	0.25	0.28	0.31	0.34	0.37	0.40	0.43	0.47
Hot Water	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.02	0.02	0.02	0.02
HVAC	0.04	0.08	0.12	0.16	0.21	0.24	0.26	0.29	0.32	0.34	0.37	0.39	0.41	0.44	0.46
Lighting	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Commercial	**0.25**	**0.59**	**1.03**	**1.21**	**1.43**	**1.45**	**1.47**	**1.49**	**1.51**	**1.53**	**1.58**	**1.64**	**1.69**	**1.74**	**1.79**
Envelope	0.00	0.00	0.01	0.01	0.02	0.03	0.03	0.04	0.04	0.05	0.05	0.06	0.06	0.07	0.07
Hot Water	0.00	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.03	0.02
HVAC	0.03	0.06	0.11	0.17	0.24	0.30	0.35	0.40	0.45	0.50	0.55	0.61	0.66	0.71	0.55
Kitchen	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.01
Lighting	0.21	0.47	0.80	0.82	0.85	0.75	0.65	0.55	0.45	0.35	0.25	0.15	0.05	-0.05	0.23
Motor/Compressor	0.01	0.04	0.10	0.18	0.29	0.35	0.41	0.47	0.53	0.59	0.65	0.72	0.78	0.84	0.90
Office Equipment	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Process	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Refrigeration	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Industrial	**0.01**	**0.02**	**0.05**	**0.09**	**0.13**	**0.15**	**0.17**	**0.20**	**0.22**	**0.25**	**0.25**	**0.25**	**0.25**	**0.25**	**0.25**
Envelope	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hot Water	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HVAC	0.01	0.02	0.05	0.09	0.12	0.15	0.17	0.19	0.22	0.24	0.26	0.29	0.31	0.34	0.24
Kitchen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lighting	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Motor/Compressor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01
Office Equipment	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Process	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Refrigeration	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table F- 3: Cumulative Savings by End-Use: ISO System (GWh)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Residential	**0.417**	**0.859**	**1.317**	**1.623**	**1.938**	**2.077**	**2.216**	**2.355**	**2.494**	**2.632**	**2.567**	**2.501**	**2.435**	**2.369**	**2.303**
Appliance	0.025	0.078	0.161	0.264	0.401	0.457	0.512	0.568	0.624	0.679	0.706	0.733	0.760	0.787	0.814
Behavioral	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Envelope	0.042	0.087	0.136	0.190	0.247	0.288	0.329	0.369	0.410	0.451	0.492	0.533	0.573	0.614	0.655
Hot Water	0.067	0.132	0.193	0.244	0.281	0.306	0.331	0.357	0.382	0.408	0.377	0.347	0.316	0.286	0.255
HVAC	0.033	0.067	0.099	0.131	0.161	0.179	0.198	0.216	0.235	0.253	0.253	0.252	0.251	0.251	0.250
Lighting	0.198	0.395	0.588	0.626	0.655	0.657	0.659	0.661	0.663	0.665	0.565	0.464	0.364	0.264	0.163
Other	0.052	0.100	0.140	0.168	0.194	0.190	0.186	0.183	0.179	0.175	0.173	0.172	0.170	0.168	0.166
Commercial	**0.560**	**1.143**	**1.745**	**1.867**	**2.183**	**2.159**	**2.135**	**2.110**	**2.086**	**2.062**	**2.055**	**2.048**	**2.041**	**2.034**	**2.027**
Envelope	0.001	0.002	0.004	0.008	0.012	0.015	0.017	0.020	0.022	0.025	0.028	0.030	0.033	0.035	0.038
Hot Water	0.001	0.002	0.004	0.006	0.008	0.010	0.012	0.015	0.017	0.019	0.019	0.020	0.020	0.021	0.021
HVAC	0.001	0.002	0.004	0.006	0.009	0.010	0.012	0.014	0.016	0.017	0.018	0.018	0.019	0.019	0.020
Kitchen	0.000	0.001	0.002	0.003	0.006	0.008	0.010	0.012	0.014	0.017	0.018	0.020	0.022	0.024	0.026
Lighting	0.553	1.123	1.703	1.791	2.062	1.997	1.932	1.867	1.803	1.738	1.699	1.661	1.622	1.583	1.544
Motor/Compressor	0.002	0.007	0.016	0.030	0.049	0.067	0.086	0.105	0.123	0.142	0.160	0.179	0.197	0.216	0.234
Office Equipment	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Other	0.001	0.004	0.008	0.014	0.023	0.030	0.038	0.045	0.053	0.061	0.067	0.074	0.080	0.087	0.094
Process	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Refrigeration	0.001	0.002	0.005	0.009	0.015	0.021	0.026	0.032	0.038	0.043	0.045	0.046	0.047	0.048	0.050

MID PROGRAM SCENARIO – MID-RATES CASE

Table F- 4: Cumulative Savings by End-Use: IIC System (GWh)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Residential	**30.13**	**48.65**	**69.56**	**87.87**	**107.25**	**118.27**	**129.28**	**140.29**	**151.31**	**162.32**	**165.16**	**167.99**	**170.83**	**173.66**	**176.50**
Appliance	0.74	2.27	4.65	7.58	11.44	13.17	14.90	16.63	18.37	20.10	20.82	21.54	22.27	22.99	23.71
Behavioral	14.03	14.02	14.02	14.01	14.01	14.01	14.01	14.01	14.00	14.00	14.00	13.99	13.99	13.99	13.98
Envelope	4.17	8.96	14.47	20.78	27.82	32.56	37.30	42.04	46.77	51.51	56.27	61.04	65.80	70.56	75.32
Hot Water	3.29	6.53	9.57	12.14	14.00	15.26	16.52	17.78	19.04	20.30	18.77	17.24	15.71	14.18	12.65
HVAC	4.72	9.64	14.72	20.71	26.90	30.28	33.66	37.03	40.41	43.79	44.77	45.76	46.75	47.74	48.73
Lighting	3.17	7.19	12.06	12.53	12.94	12.84	12.75	12.66	12.56	12.47	10.35	8.24	6.13	4.01	1.90
Other	0.01	0.04	0.07	0.10	0.14	0.15	0.15	0.15	0.16	0.16	0.17	0.18	0.19	0.19	0.20
Commercial	**14.80**	**31.14**	**49.14**	**58.27**	**70.16**	**73.35**	**76.54**	**79.73**	**82.91**	**86.10**	**87.19**	**88.28**	**89.37**	**90.46**	**91.55**
Envelope	0.12	0.44	0.99	1.84	3.00	3.90	4.79	5.69	6.59	7.48	8.38	9.28	10.18	11.08	11.98
Hot Water	0.37	0.78	1.25	1.76	2.30	2.65	3.00	3.35	3.69	4.04	4.11	4.19	4.26	4.33	4.41
HVAC	0.58	1.58	3.06	4.92	7.11	8.93	10.76	12.59	14.41	16.24	17.52	18.80	20.07	21.35	22.63
Kitchen	0.04	0.13	0.29	0.54	0.91	1.27	1.64	2.00	2.36	2.73	2.98	3.23	3.49	3.74	3.99
Lighting	13.48	27.51	41.97	46.44	52.49	51.29	50.09	48.89	47.69	46.48	44.32	42.15	39.98	37.81	35.65
Motor/Compressor	0.11	0.39	0.89	1.63	2.60	3.19	3.77	4.35	4.93	5.51	6.10	6.68	7.27	7.85	8.43
Office Equipment	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Other	0.07	0.24	0.50	0.82	1.23	1.46	1.70	1.93	2.16	2.39	2.51	2.63	2.74	2.86	2.97
Process	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Refrigeration	0.02	0.08	0.18	0.32	0.51	0.65	0.79	0.93	1.07	1.21	1.26	1.32	1.37	1.42	1.48
Industrial	**0.60**	**1.56**	**2.97**	**4.85**	**7.21**	**8.57**	**9.93**	**11.29**	**12.65**	**14.01**	**15.02**	**16.04**	**17.05**	**18.07**	**19.08**
Envelope	0.12	0.44	0.99	1.84	3.00	3.90	4.79	5.69	6.59	7.48	8.38	9.28	10.18	11.08	11.98
Hot Water	0.37	0.78	1.25	1.76	2.30	2.65	3.00	3.35	3.69	4.04	4.11	4.19	4.26	4.33	4.41
HVAC	0.58	1.58	3.06	4.92	7.11	8.93	10.76	12.59	14.41	16.24	17.52	18.80	20.07	21.35	22.63
Kitchen	0.04	0.13	0.29	0.54	0.91	1.27	1.64	2.00	2.36	2.73	2.98	3.23	3.49	3.74	3.99
Lighting	13.48	27.51	41.97	46.44	52.49	51.29	50.09	48.89	47.69	46.48	44.32	42.15	39.98	37.81	35.65
Motor/Compressor	0.11	0.39	0.89	1.63	2.60	3.19	3.77	4.35	4.93	5.51	6.10	6.68	7.27	7.85	8.43
Office Equipment	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Other	0.07	0.24	0.50	0.82	1.23	1.46	1.70	1.93	2.16	2.39	2.51	2.63	2.74	2.86	2.97
Process	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Refrigeration	0.02	0.08	0.18	0.32	0.51	0.65	0.79	0.93	1.07	1.21	1.26	1.32	1.37	1.42	1.48

Table F- 5: Cumulative Achievable Potential by End-Use: LAB System (GWh)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Residential	**0.74**	**0.86**	**1.01**	**1.19**	**1.39**	**1.50**	**1.61**	**1.73**	**1.84**	**1.95**	**2.03**	**2.11**	**2.19**	**2.27**	**2.34**
Appliance	0.00	0.00	0.01	0.02	0.03	0.04	0.05	0.05	0.06	0.07	0.08	0.08	0.09	0.10	0.10
Behavioral	0.63	0.63	0.63	0.63	0.63	0.63	0.63	0.63	0.63	0.63	0.63	0.63	0.63	0.63	0.63
Envelope	0.02	0.04	0.08	0.13	0.20	0.24	0.27	0.31	0.35	0.39	0.42	0.46	0.50	0.54	0.58
Hot Water	0.02	0.04	0.06	0.08	0.09	0.10	0.10	0.11	0.12	0.13	0.12	0.11	0.10	0.09	0.08
HVAC	0.06	0.13	0.21	0.31	0.43	0.49	0.55	0.61	0.67	0.73	0.77	0.82	0.86	0.91	0.95
Lighting	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00
Other	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Commercial	**0.52**	**1.17**	**1.99**	**2.31**	**2.73**	**2.77**	**2.81**	**2.86**	**2.90**	**2.94**	**3.08**	**3.22**	**3.36**	**3.49**	**3.63**
Envelope	0.00	0.01	0.03	0.05	0.09	0.11	0.13	0.16	0.18	0.20	0.23	0.25	0.27	0.29	0.32
Hot Water	0.01	0.01	0.02	0.02	0.03	0.03	0.04	0.04	0.04	0.04	0.05	0.05	0.05	0.06	0.05
HVAC	0.03	0.08	0.16	0.25	0.35	0.42	0.50	0.58	0.65	0.73	0.80	0.88	0.95	1.03	0.82
Kitchen	0.00	0.00	0.00	0.01	0.01	0.01	0.02	0.02	0.02	0.03	0.03	0.03	0.04	0.04	0.04
Lighting	0.45	0.97	1.58	1.60	1.66	1.47	1.28	1.10	0.91	0.72	0.54	0.35	0.16	-0.03	0.58
Motor/Compressor	0.03	0.09	0.20	0.37	0.59	0.71	0.84	0.96	1.08	1.21	1.33	1.45	1.58	1.70	1.82
Office Equipment	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Process	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Refrigeration	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Industrial	**0.01**	**0.04**	**0.08**	**0.13**	**0.18**	**0.21**	**0.25**	**0.28**	**0.32**	**0.35**	**0.35**	**0.35**	**0.35**	**0.36**	**0.36**
Envelope	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hot Water	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HVAC	0.01	0.03	0.07	0.12	0.17	0.20	0.23	0.27	0.30	0.33	0.36	0.40	0.43	0.46	0.33
Kitchen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lighting	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Motor/Compressor	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.02
Office Equipment	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Process	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01
Refrigeration	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table F- 6: Cumulative Savings by End-Use (ISO)(GWh)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Residential	0.417	0.859	1.317	1.623	1.938	2.077	2.216	2.355	2.494	2.632	2.567	2.501	2.435	2.369	2.303
Appliance	0.025	0.078	0.161	0.264	0.401	0.457	0.512	0.568	0.624	0.679	0.706	0.733	0.760	0.787	0.814
Behavioral	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Envelope	0.042	0.087	0.136	0.190	0.247	0.288	0.329	0.369	0.410	0.451	0.492	0.533	0.573	0.614	0.655
Hot Water	0.067	0.132	0.193	0.244	0.281	0.306	0.331	0.357	0.382	0.408	0.377	0.347	0.316	0.286	0.255
HVAC	0.033	0.067	0.099	0.131	0.161	0.179	0.198	0.216	0.235	0.253	0.253	0.252	0.251	0.251	0.250
Lighting	0.198	0.395	0.588	0.626	0.655	0.657	0.659	0.661	0.663	0.665	0.565	0.464	0.364	0.264	0.163
Other	0.052	0.100	0.140	0.168	0.194	0.190	0.186	0.183	0.179	0.175	0.173	0.172	0.170	0.168	0.166
Commercial	0.603	1.234	1.893	2.053	2.432	2.424	2.416	2.409	2.401	2.393	2.383	2.373	2.364	2.354	2.344
Envelope	0.001	0.002	0.005	0.010	0.016	0.019	0.023	0.026	0.030	0.033	0.037	0.040	0.043	0.047	0.050
Hot Water	0.001	0.002	0.004	0.007	0.010	0.013	0.016	0.018	0.021	0.024	0.025	0.025	0.026	0.027	0.028
HVAC	0.001	0.002	0.004	0.007	0.010	0.012	0.014	0.016	0.018	0.020	0.021	0.022	0.022	0.023	0.024
Kitchen	0.000	0.001	0.002	0.004	0.007	0.010	0.013	0.016	0.019	0.021	0.024	0.026	0.029	0.031	0.033
Lighting	0.596	1.210	1.840	1.959	2.282	2.224	2.167	2.109	2.051	1.993	1.944	1.895	1.846	1.797	1.748
Motor/Compressor	0.003	0.009	0.020	0.037	0.061	0.084	0.108	0.131	0.154	0.177	0.201	0.224	0.247	0.270	0.293
Office Equipment	0.000	0.000	0.000	0.000	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
Other	0.001	0.004	0.009	0.017	0.026	0.035	0.044	0.052	0.061	0.069	0.076	0.083	0.091	0.098	0.105
Process	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Refrigeration	0.001	0.003	0.006	0.011	0.019	0.026	0.033	0.040	0.047	0.053	0.055	0.057	0.058	0.060	0.061

UPPER PROGRAM SCENARIO – MID-RATES CASE

Table F- 7: Cumulative Savings by End-Use: IIC System (GWh)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Residential	**44.42**	**73.63**	**106.11**	**134.45**	**164.50**	**180.81**	**197.12**	**213.43**	**229.74**	**246.05**	**249.57**	**253.08**	**256.60**	**260.11**	**263.62**
Appliance	1.33	4.19	8.54	13.71	20.45	22.57	24.69	26.81	28.94	31.06	31.26	31.46	31.67	31.87	32.07
Behavioral	18.70	18.70	18.69	18.69	18.68	18.68	18.68	18.67	18.67	18.67	18.66	18.66	18.65	18.65	18.65
Envelope	7.34	15.60	24.98	35.57	47.28	55.28	63.27	71.26	79.25	87.24	95.25	103.26	111.27	119.28	127.30
Hot Water	4.83	9.59	14.05	17.86	20.65	22.57	24.48	26.40	28.31	30.23	28.03	25.84	23.64	21.44	19.24
HVAC	6.34	12.89	19.60	27.42	35.43	39.82	44.22	48.61	53.00	57.39	58.42	59.44	60.46	61.49	62.51
Lighting	5.85	12.60	20.11	21.00	21.73	21.61	21.50	21.39	21.27	21.16	17.62	14.09	10.55	7.02	3.48
Other	0.03	0.08	0.14	0.20	0.27	0.28	0.29	0.29	0.30	0.31	0.32	0.33	0.34	0.36	0.37
Commercial	**18.21**	**38.59**	**61.42**	**74.60**	**92.01**	**97.27**	**102.53**	**107.79**	**113.05**	**118.31**	**120.42**	**122.54**	**124.66**	**126.78**	**128.89**
Envelope	0.20	0.68	1.55	2.87	4.68	6.05	7.42	8.79	10.17	11.54	12.92	14.29	15.67	17.04	18.42
Hot Water	0.45	0.97	1.60	2.32	3.14	3.72	4.30	4.88	5.46	6.04	6.21	6.38	6.54	6.71	6.88
HVAC	0.83	2.28	4.48	7.26	10.56	13.34	16.12	18.90	21.68	24.46	26.50	28.53	30.56	32.59	34.63
Kitchen	0.05	0.16	0.38	0.70	1.18	1.65	2.12	2.59	3.06	3.53	3.85	4.18	4.51	4.83	5.16
Lighting	16.38	33.41	51.05	57.34	66.10	64.75	63.41	62.07	60.72	59.38	56.56	53.74	50.92	48.11	45.29
Motor/Compressor	0.14	0.48	1.09	1.99	3.19	3.95	4.70	5.45	6.20	6.95	7.71	8.46	9.21	9.97	10.72
Office Equipment	0.00	0.00	0.01	0.01	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Other	0.14	0.47	0.98	1.58	2.36	2.78	3.20	3.61	4.03	4.45	4.63	4.81	5.00	5.18	5.36
Process	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Refrigeration	0.04	0.13	0.28	0.50	0.79	1.02	1.25	1.48	1.70	1.93	2.03	2.12	2.22	2.31	2.41
Industrial	**0.84**	**2.19**	**4.20**	**6.86**	**10.24**	**12.22**	**14.20**	**16.18**	**18.15**	**20.13**	**21.63**	**23.13**	**24.64**	**26.14**	**27.64**
Envelope	0.02	0.06	0.14	0.25	0.40	0.49	0.57	0.66	0.74	0.83	0.92	1.00	1.09	1.17	1.26
Hot Water	0.08	0.16	0.24	0.33	0.43	0.47	0.50	0.54	0.57	0.61	0.62	0.63	0.64	0.65	0.66
HVAC	0.08	0.25	0.53	0.90	1.36	1.73	2.09	2.45	2.81	3.17	3.47	3.77	4.07	4.37	4.66
Kitchen	0.00	0.00	0.01	0.02	0.03	0.05	0.06	0.08	0.09	0.10	0.11	0.12	0.12	0.13	0.14
Lighting	0.41	0.84	1.30	1.76	2.27	2.44	2.60	2.77	2.94	3.10	2.96	2.81	2.66	2.52	2.37
Motor/Compressor	0.23	0.79	1.78	3.27	5.25	6.45	7.66	8.87	10.08	11.28	12.47	13.65	14.83	16.02	17.20
Office Equipment	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other	0.02	0.08	0.17	0.27	0.42	0.51	0.60	0.69	0.78	0.87	0.92	0.98	1.03	1.09	1.14
Process	0.01	0.02	0.03	0.04	0.05	0.05	0.06	0.06	0.06	0.07	0.07	0.08	0.08	0.09	0.09
Refrigeration	0.00	0.00	0.01	0.02	0.03	0.04	0.05	0.07	0.08	0.09	0.09	0.10	0.10	0.10	0.11

Table F- 8: Cumulative Savings by End-Use: LAB System (GWh)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Residential	**1.07**	**1.34**	**1.65**	**2.03**	**2.47**	**2.70**	**2.94**	**3.17**	**3.40**	**3.64**	**3.77**	**3.91**	**4.05**	**4.18**	**4.32**
Appliance	0.01	0.03	0.05	0.08	0.12	0.14	0.15	0.16	0.17	0.18	0.19	0.19	0.19	0.19	0.19
Behavioral	0.85	0.85	0.85	0.85	0.84	0.84	0.84	0.84	0.84	0.84	0.84	0.84	0.84	0.84	0.84
Envelope	0.03	0.09	0.17	0.28	0.41	0.50	0.58	0.66	0.74	0.83	0.91	0.99	1.07	1.16	1.24
Hot Water	0.05	0.10	0.14	0.18	0.20	0.22	0.24	0.25	0.27	0.29	0.26	0.24	0.22	0.19	0.17
HVAC	0.13	0.27	0.42	0.63	0.86	0.98	1.11	1.23	1.35	1.47	1.55	1.63	1.71	1.79	1.87
Lighting	0.00	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01	0.01	0.00
Other	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Commercial	**0.86**	**1.89**	**3.11**	**3.61**	**4.30**	**4.41**	**4.53**	**4.64**	**4.75**	**4.86**	**5.11**	**5.36**	**5.60**	**5.85**	**6.10**
Envelope	0.01	0.03	0.07	0.12	0.20	0.25	0.30	0.35	0.40	0.45	0.50	0.55	0.60	0.65	0.70
Hot Water	0.01	0.02	0.03	0.04	0.05	0.05	0.05	0.06	0.06	0.07	0.07	0.07	0.07	0.07	0.07
HVAC	0.05	0.12	0.23	0.36	0.50	0.61	0.72	0.83	0.94	1.05	1.08	1.11	1.14	1.17	1.20
Kitchen	0.00	0.00	0.01	0.01	0.02	0.03	0.03	0.04	0.05	0.06	0.06	0.07	0.07	0.08	0.08
Lighting	0.75	1.59	2.48	2.51	2.64	2.39	2.14	1.90	1.65	1.40	1.38	1.35	1.33	1.30	1.28
Motor/Compressor	0.04	0.13	0.30	0.55	0.88	1.07	1.25	1.44	1.62	1.81	1.99	2.18	2.36	2.55	2.73
Office Equipment	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other	0.00	0.00	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Process	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Refrigeration	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Industrial	**0.02**	**0.05**	**0.10**	**0.16**	**0.23**	**0.27**	**0.32**	**0.36**	**0.40**	**0.45**	**0.45**	**0.45**	**0.46**	**0.46**	**0.46**
Envelope	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
Hot Water	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HVAC	0.01	0.04	0.08	0.14	0.20	0.24	0.28	0.32	0.36	0.40	0.40	0.39	0.39	0.39	0.39
Kitchen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lighting	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Motor/Compressor	0.00	0.00	0.00	0.01	0.01	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.04	0.04
Office Equipment	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Process	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.02
Refrigeration	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table F- 9: Cumulative Savings by End-Use: ISO System (GWh)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Residential	0.458	0.942	1.445	1.779	2.123	2.274	2.424	2.575	2.726	2.877	2.803	2.730	2.656	2.583	2.509
Appliance	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027
Behavioral	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Envelope	0.046	0.046	0.046	0.046	0.046	0.046	0.046	0.046	0.046	0.046	0.046	0.046	0.046	0.046	0.046
Hot Water	0.074	0.074	0.074	0.074	0.074	0.074	0.074	0.074	0.074	0.074	0.074	0.074	0.074	0.074	0.074
HVAC	0.036	0.036	0.036	0.036	0.036	0.036	0.036	0.036	0.036	0.036	0.036	0.036	0.036	0.036	0.036
Lighting	0.218	0.218	0.218	0.218	0.218	0.218	0.218	0.218	0.218	0.218	0.218	0.218	0.218	0.218	0.218
Other	0.057	0.057	0.057	0.057	0.057	0.057	0.057	0.057	0.057	0.057	0.057	0.057	0.057	0.057	0.057
Commercial	0.709	1.457	2.247	2.480	2.985	2.994	3.003	3.012	3.022	3.031	3.025	3.020	3.014	3.009	3.003
Envelope	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
Hot Water	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
HVAC	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
Kitchen	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Lighting	0.699	0.699	0.699	0.699	0.699	0.699	0.699	0.699	0.699	0.699	0.699	0.699	0.699	0.699	0.699
Motor/Compressor	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004
Office Equipment	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Other	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Process	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Refrigeration	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001

DETAILED RATE SENSITIVITY RESULTS CUMULATIVE SAVINGS

The tables below present the cumulative savings for CDM programs - not including savings from program years prior to 2020.

LOWER PROGRAM SCENARIO

Table F- 10: Cumulative Savings by Sector: IIC System (GWh)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Total
High Rates																
Residential	22	35	48	60	72	80	87	95	103	111	114	118	121	125	128	1,319
Commercial	13	27	43	49	58	59	61	62	64	65	66	66	66	67	67	833
Industrial	0	1	2	4	6	7	8	9	10	11	12	12	13	14	15	124
Total	**35**	**63**	**93**	**113**	**136**	**146**	**156**	**166**	**177**	**187**	**192**	**196**	**200**	**206**	**210**	2,276
Low Rates																
Residential	18	26	34	42	50	55	60	65	71	76	79	81	84	87	90	918
Commercial	11	22	35	40	45	46	47	47	48	48	49	49	50	50	50	637
Industrial	0	1	2	3	4	5	5	6	7	8	8	9	9	10	11	88
Total	**29**	**49**	**71**	**85**	**99**	**106**	**112**	**118**	**126**	**132**	**136**	**139**	**143**	**147**	**151**	1,643

MID PROGRAM SCENARIO

Table F- 11: Cumulative Savings by Sector: IIC System (GWh)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Total
High Rates																
Residential	33	55	80	101	123	136	148	161	174	186	189	192	195	198	201	2,172
Commercial	16	33	53	63	76	80	84	87	91	95	96	98	99	100	101	1,172
Industrial	1	2	3	5	8	10	11	13	14	16	17	18	19	20	21	178
Total	**50**	**90**	**136**	**169**	**207**	**226**	**243**	**261**	**279**	**297**	**302**	**308**	**313**	**318**	**323**	3,522
Low Rates																
Residential	27	43	60	75	91	100	110	119	128	137	140	142	145	147	150	1,614
Commercial	14	29	46	53	63	66	68	71	74	76	77	78	79	80	80	954
Industrial	1	1	3	4	6	7	9	10	11	12	13	14	15	16	17	139
Total	**42**	**73**	**109**	**132**	**160**	**173**	**187**	**200**	**213**	**225**	**230**	**234**	**239**	**243**	**247**	2,707

UPPER PROGRAM SCENARIO

Table F- 12: Cumulative Savings by Sector: IIC System (GWh)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Total
High Rates																
Residential	48	80	116	147	180	198	216	234	252	270	274	277	281	285	289	3,147
Commercial	19	40	64	79	98	103	109	115	121	127	129	132	134	137	139	1,546
Industrial	1	2	5	7	11	13	15	18	20	22	24	25	27	29	30	249
Total	**68**	**122**	**185**	**233**	**289**	**314**	**340**	**367**	**393**	**419**	**427**	**434**	**442**	**451**	**458**	4,942
Low Rates																
Residential	41	67	95	120	147	161	176	190	205	219	222	225	228	231	234	2,561
Commercial	17	37	58	70	86	90	94	99	103	108	109	111	113	114	116	1,325
Industrial	1	2	4	6	9	11	13	15	16	18	19	21	22	23	25	205
Total	**59**	**106**	**157**	**196**	**242**	**262**	**283**	**304**	**324**	**345**	**350**	**357**	**363**	**368**	**375**	4,091

DETAILED DEMAND RESPONSE RESULTS

The following section provides detailed results tables for the demand response analysis.

Table F- 13 and **Table F-14** present the measure-level potential results for cost-effective measures at each assessment year in the study period for the IIC system. Technical and economical potential was not assessed for the LAB system as Dunsky extended IIC programs to LAB, in agreement with NL Utilities.

Table F- 13: Residential Technical and Economic Potential (MW)

System	Measure	Tech Potential 2020	Tech Potential 2024	Tech Potential 2029	Tech Potential 2034	Economic Potential 2020	Economic Potential 2024	Economic Potential 2029	Economic Potential 2034
IIC	**Setpoint Control**	428	440	464	478	28	30	31	32
IIC	**Domestic Hot Water**	230	236	249	256	24	25	26	27
IIC	**Clothes Dryer**	207	212	222	228	21	22	23	24
IIC	**Hot Tubs / Spas**	1.5	1.6	1.7	1.8	0.4	0.4	0.4	0.4
IIC	**Dual-Fuel**	21	21	22	22	21	21	22	22
IIC	**TOU**	8.0	8.6	9.0	9.8	8.0	8.6	9.0	9.8

Table F- 14: C&I Technical and Economic Potential (MW)

System	Measure	Tech Potential 2020	Tech Potential 2024	Tech Potential 2029	Tech Potential 2034	Economic Potential 2020	Economic Potential 2024	Economic Potential 2029	Economic Potential 2034
IIC	**Anti-Sweat Heater Control**	3.2	3.3	3.4	3.5	0.4	0.4	0.5	0.5
IIC	**Commercial Refrigeration**	12	13	13	13	1.6	1.6	1.7	1.7
IIC	**Interruption of Humidification (Manual or BAS)**	11	11	12	12	1.4	1.4	1.5	1.5
IIC	**Interruption of Winter Cooling/Free Cooling Systems**	1.2	1.3	1.3	1.4	0.2	0.2	0.2	0.2
IIC	**Lighting Control (Manual) for Fuel Heated Buildings**	9.3	10	10	10	1.1	1.2	1.2	1.3
IIC	**Reduction of fresh air flow (Manual or BAS)**	24	24	26	26	3.6	3.7	3.9	3.9
IIC	**Reduction of Ventilation Flow (with VAVs)**	39	40	42	43	5.5	5.7	6.0	6.2
IIC	**Setpoint Control for Electric Heated Building (Manual)**	78	80	84	87	10	10	11	11
IIC	**Dual-Fuel**	46	48	49	50	46	48	49	50
IIC	**Small & Medium Industrials**	33	33	32	32	33	33	32	32
IIC	**Large Industrial Curtailment**	125	125	125	125	125	125	125	125
IIC	**TOU Rates**	3.0	3.4	3.5	3.8	3.0	3.4	3.5	3.8

Table F- 15, Table F- 16, Table F- 17, and **Table F- 18** present the program costs, potential peak reduction and PACT for each study period. Because of their small size, LAB DR programs were integrated with IIC programs.

Table F- 15: DR Program Results – 2020 Implementation

DR Program	Scenario	Peak Reduction (MW)[58]	Total Benefits [59] ($M 2020)	Total Costs [60] ($M 2020)	PACT[61]
Residential DLC	**Equipment Control Expansion**	25	$152	$21	6.3
Commercial curtailment	**Equipment Control Expansion**	4.3	$4.0	$3.7	0.9
TOU – IIC Only62	**Rate-based Expansion**	11	$55	$97	0.6
Backup Generation	**All**	27	$215	$114	1.9
Industrial curtailment	**Equipment Control Expansion**	112	$405	$13	31.7
Industrial curtailment	**Rate-based Expansion**	104	$376	$14	27.0
Industrial curtailment	**Optimize Existing Curtailment**	152	$550	$17	32.8

Table F- 16:DR Program Results – 2024 Implementation

DR Program	Scenario	Peak Reduction (MW)	Total Benefits ($M 2020)	Total Costs ($M 2020)	PACT
Residential DLC	**Equipment Control Expansion**	26	$174	$22	6.8
Commercial curtailment	**Equipment Control Expansion**	4.7	$4.7	$6.7	0.6
TOU – IIC Only	**Rate-based Expansion**	12	$66	$97	0.7
Backup Generation	**All**	27	$239	$118	2.0
Industrial curtailment	**Equipment Control Expansion**	114	$453	$13	34.8
Industrial curtailment	**Rate-based Expansion**	105	$414	$14	28.8
Industrial curtailment	**Optimize Existing Curtailment**	153	$603	$17	35

[58] At full deployment (For new programs: after a 5-year ramp-up).

[59] At full deployment (For new programs: after a 5-year ramp-up).

[60] At full deployment (For new programs: after a 5-year ramp-up).

[61] Including a 5-year ramp-up for new programs.

[62] First year cost and PACT. Does not include negative impact from lost industrial curtailment potential.

Table F- 17: DR Program Results – 2029 Implementation

DR Program	Scenario	Peak Reduction (MW)	Total Benefits ($M 2020)	Total Costs ($M 2020)	PACT
Residential DLC	**Equipment Control Expansion**	27	$198	$23	7.5
Commercial curtailment	**Equipment Control Expansion**	5.2	$5.8	$7.4	0.6
TOU – IIC Only	**Rate-based Expansion**	13	$76	$97	0.8
Backup Generation	**All**	29	$269	$127	2.1
Industrial curtailment	**Equipment Control Expansion**	117	$515	$13	38.9
Industrial curtailment	**Rate-based Expansion**	108	$470	$15	31.1
Industrial curtailment	**Optimize Existing Curtailment**	154	$674	$18	37.6

Table F- 18: DR Program Results – 2034 Implementation

DR Program	Scenario	Peak Reduction (MW)	Total Benefits ($M 2020)	Total Costs ($M 2020)	PACT
Residential DLC	**Equipment Control Expansion**	28	$225	$24	8.3
Commercial curtailment	**Equipment Control Expansion**	5.5	$6.9	$7.8	0.7
TOU – IIC Only	**Rate-based Expansion**	13	$87	$97	0.9
Backup Generation	**All**	30	$303	$132	2.3
Industrial curtailment	**Equipment Control Expansion**	120	$583	$13	43.4
Industrial curtailment	**Rate-based Expansion**	109	$527	$15	34.3
Industrial curtailment	**Optimize Existing Curtailment**	154	$745	$18	40.7

DEMAND RESPONSE PROGRAM COST-EFFECTIVENESS

Based on the DR scenarios, the peak reduction potential and cost-effectiveness for each program stream was assessed considering program costs (including customer incentives, set up costs, program ramp-up, and marketing costs) and benefits (including peak capacity avoided costs and ancillary benefits such as peak hour generation reduction benefits and voltage regulation where applicable).

Key findings from the program analysis reveal that:

- **Industrial curtailment presents the best cost-effectiveness:** Maximizing industrial curtailment and other measures with no bounce-back, like BUGs (for LAB system) and dual-fuel achieve the highest cost-effectiveness.
- **Industrial sector DR programs may suffer from being combined with other programs:** In all scenarios, industrial customer enrollment in the DR programs is expanded to reach small and medium industrials. The model savings per customer are higher in the Scenario 1, which improves cost-effectiveness as compared to the TOU and Equipment scenarios where the large industrials must exert their peak demand reductions against a utility load curve already flattened by DR programs in the other sectors.

High avoided costs

Though not presented here, a high number of manual or DLC measures pass cost-effectiveness. Due to high avoided costs and a relatively flat load shape, DLC potential is mainly constrained by the load shape. In all cases, adoption must be limited in order to limit consumption displacement. Depending on measures and their effect on peak, potential varies widely. As mentioned before, among measures with a large potential to sustain a program and positive PACT are the residential setpoint controls and domestic water heater DLC, respectively, due to the heating demand during

DYNAMIC RATE DESIGN

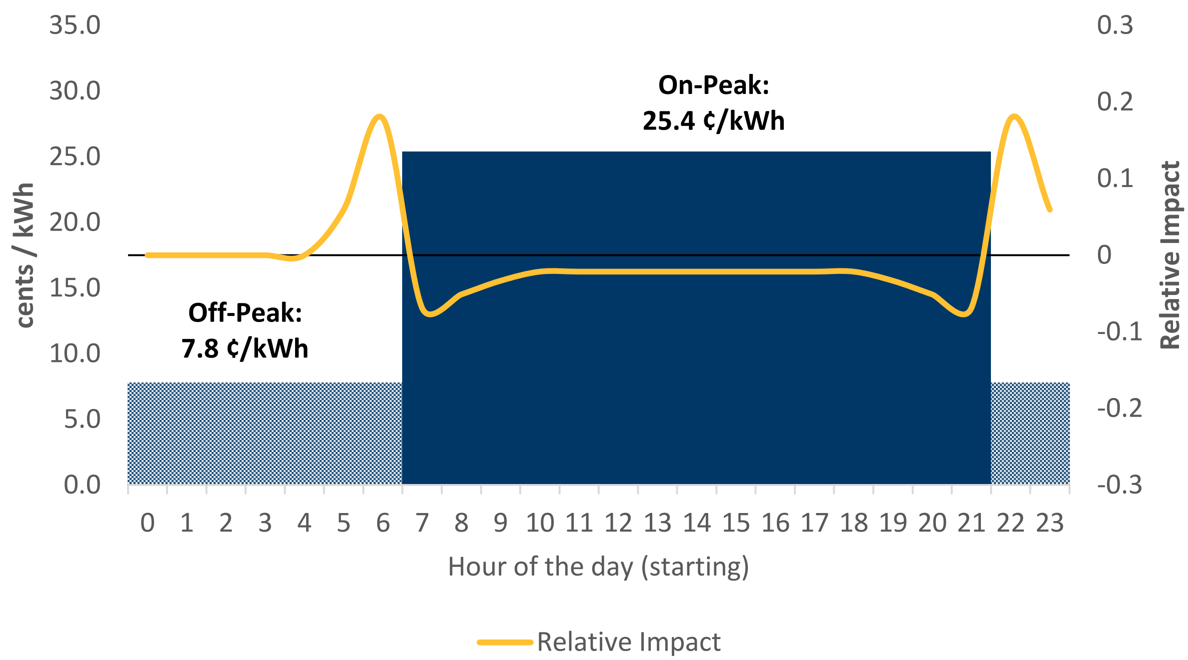
Various rate designs were tested on the IIC system standard peak day and load curves. This includes four TOU designs and one CPP design.

The analysis tested a range of TOU rate designs in the IIC systems, starting with the two-tier and three-tier models presented in the recent NL Hydro marginal cost study.[63] In the figure below, the line presents

[63] Source: "Marginal Cost Study Update – 2018", Nov. 15, 2018, NL Hydro

the relative impact of dynamic rates on demand while the filled areas define pricing (on-peak hour: 7:00 to 21:59 inclusively).

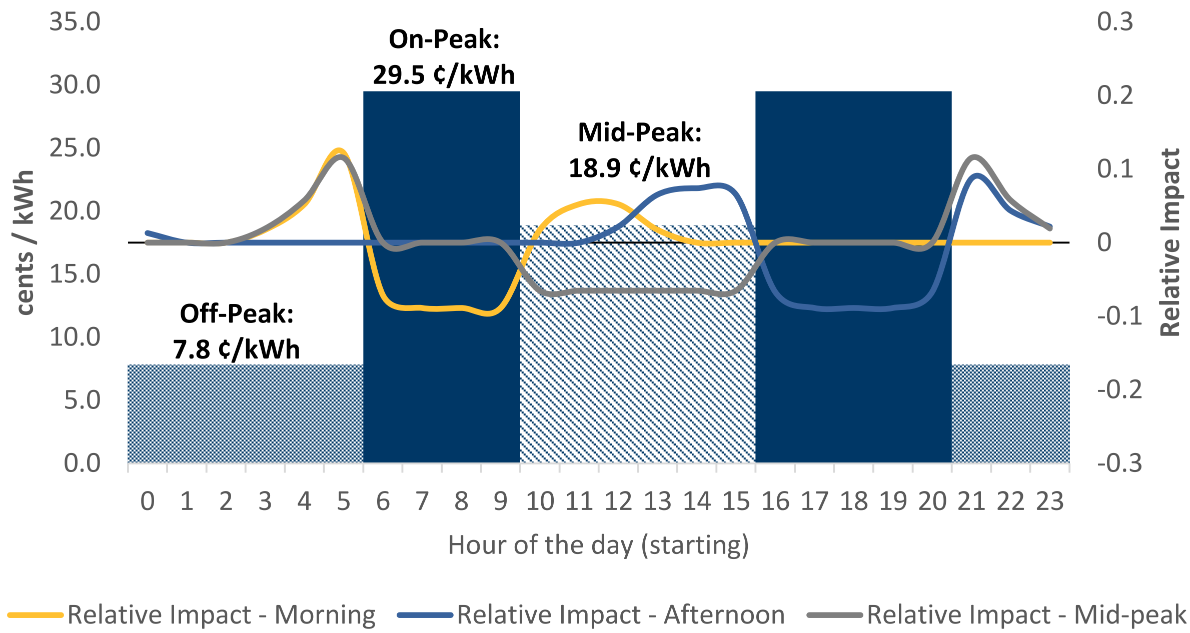
Figure F- 4: TOU Rate Design #1 (2 Tier – NL Hydro Marginal Cost Study)



The above TOU design increased the standard peak day demand by 54 MW and increased the demand in all five historical years.

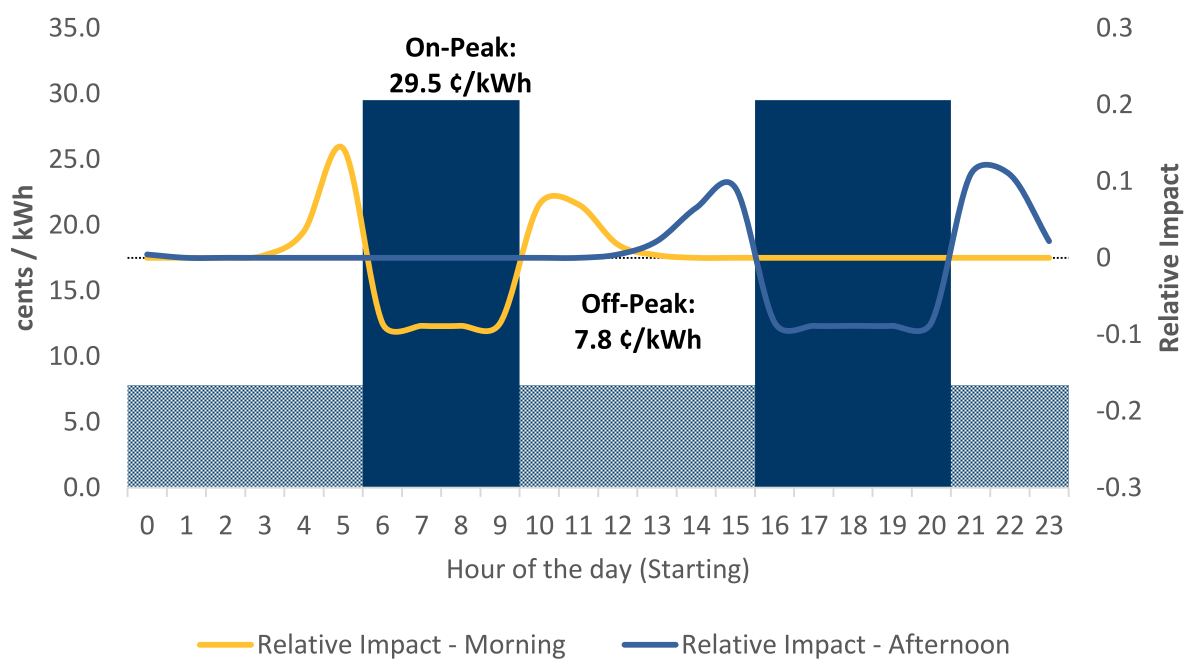
The rate design below has two on-peak segments and a single mid-peak segment in the middle of the day. The three lines show the relative impact on demand for each of these segments. For example, in the morning peak hours (6:00 to 9:59 – yellow line) the dynamic pricing impact will be to reduce demand during peak hours and increase it earlier in the morning and over mid-peak hours (demand shifting). In comparison, mid-peak (10:00 to 20:59 – grey line) will not shift demand to peak hours because of higher energy costs and will instead shift demand to the early morning or late evening.

Figure F- 5: TOU Rate Design #2 (3 Tier – NL Hydro Marginal Cost Study)



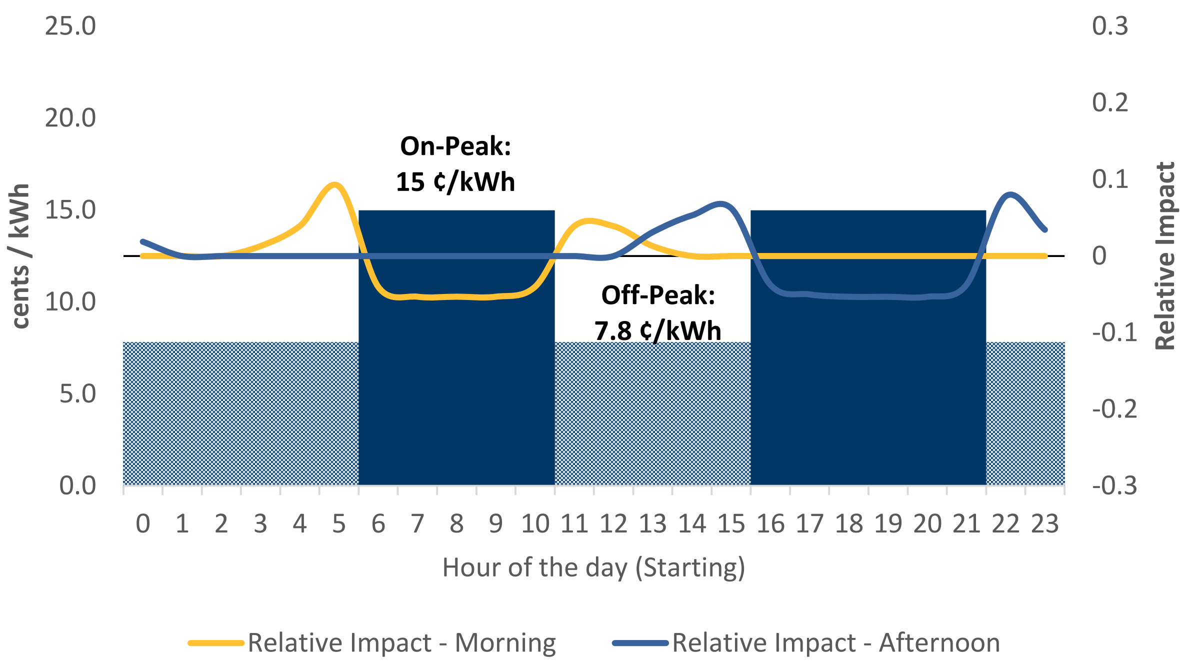
The above TOU design increased the standard peak day demand by 66 MW and increased the demand in all five historical years.

Figure F- 6: TOU Rate Design #3 (2 Tier – ≈4:1 Ratio)



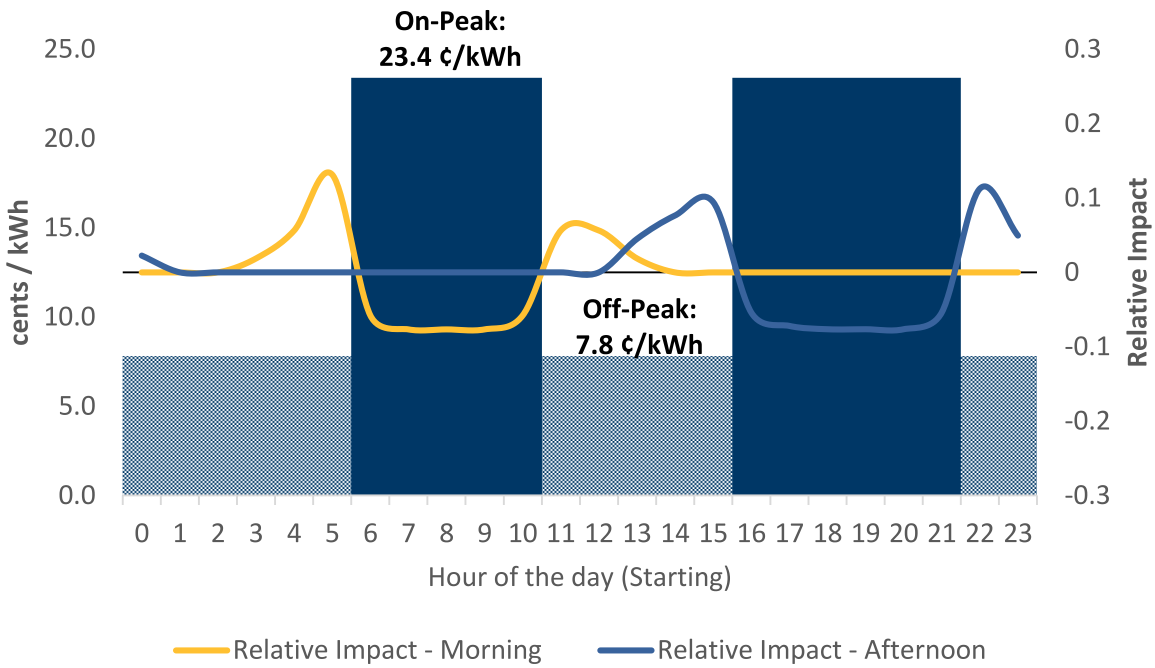
The above TOU design increased the standard peak day demand by 11 MW and increased the demand in all five historical years.

Figure F- 7: TOU Rate Design #4 (2 Tier – ≈2:1 Ratio)



The above TOU design decreased the standard peak day demand by 11 MW and decreased the demand in four years out of five historical years.

Figure F- 8: CPP Rate Design #1 (2 Tier – 3:1 Ratio)



The above CPP design increased the standard peak day demand by 16 MW and increased the demand in all five historical years. Overall, dynamic rate implementation reduces the demand saving potential from existing time constrained industrial curtailment contracts. The industrial curtailment is not as well suited to address the new peaks generated by dynamic rates. **Figure F- 9** and

Figure F- 10 respectively present the impact of large industrial curtailment on its own and combined with TOU. We see that demand savings from large industrial alone is 125 MW, while the TOU and large industrial combined is 92 MW.

Figure F- 9: Industrial curtailment impact on demand

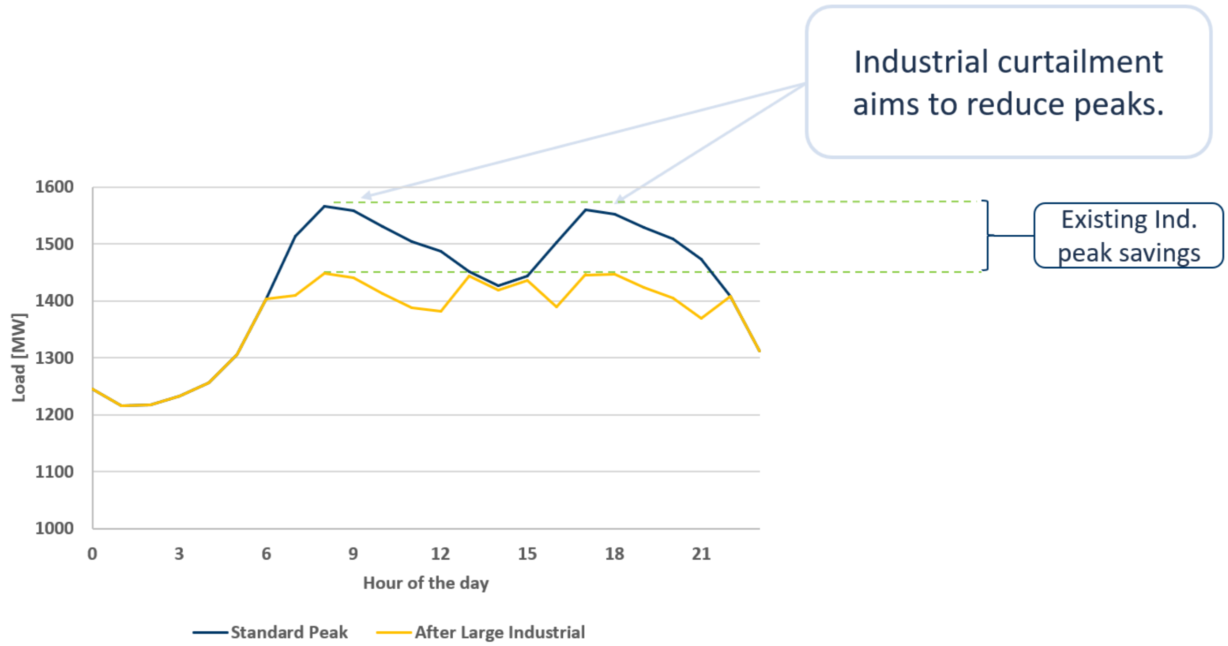
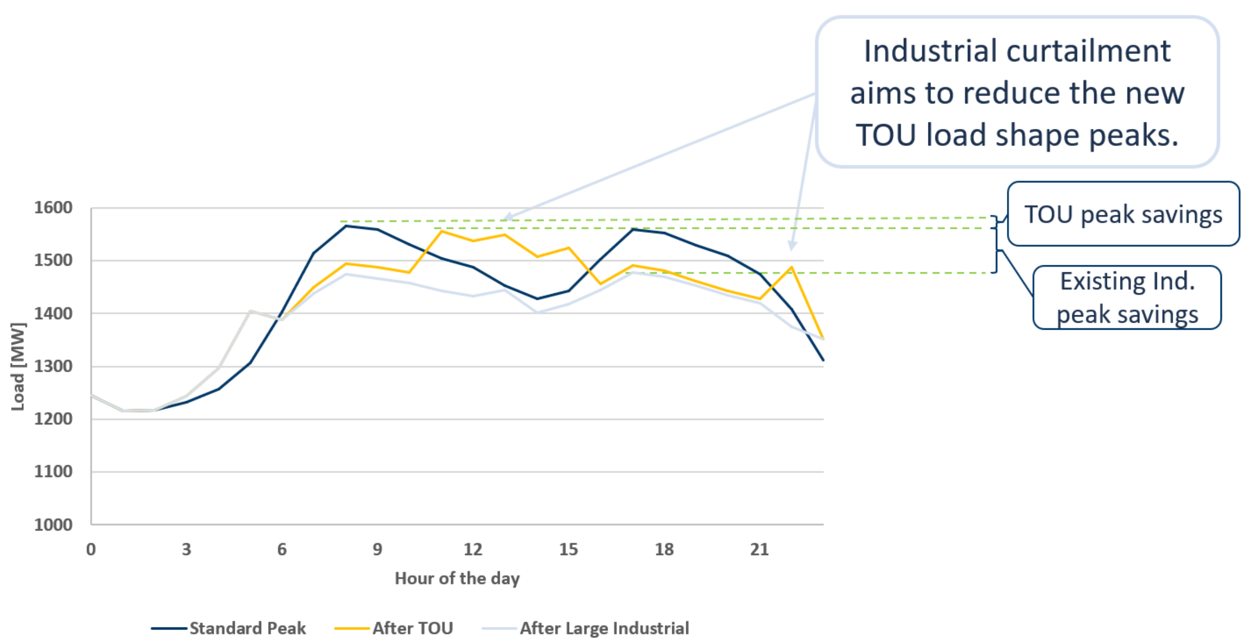


Figure F- 10: Combined TOU and industrial curtailment impact on demand



FUEL SWITCHING DETAILED RESULTS TABLES

The following section provides detailed results tables for the fuel switching analysis. It first provides detailed results for the primary analysis for each incentive scenario. Following these tables are detailed results tables for the sensitivity analyses.

PRIMARY ANALYSIS

The primary analysis tested fuel switching under the MID electricity rate scenario and no carbon pricing applied to oil rates.

Table F- 19: Percent of all customers adopting heat pump technologies (MID electricity rates, no carbon pricing)

LOWER	2020	2021	2022	2023	2024	2025 to 2029	2030 to 2034	Total
% Residential customers adopting DMSHP in electric baseboard households	1.7%	1.7%	1.6%	1.6%	1.5%	4.1%	4.1%	**16.2%**
% Residential customers adopting heat pumps for space heating	0.005%	0.005%	0.004%	0.004%	0.004%	0.014%	0.013%	**0.049%**
% Residential customers adopting heat pumps for domestic hot water heating	0.001%	0.001%	0.001%	0.001%	0.001%	0.004%	0.004%	**0.011%**
% Commercial square footage adopting heat pumps for space heating	0.008%	0.006%	0.006%	0.005%	0.005%	0.013%	0.012%	**0.054%**
% Commercial customers adopting heat pumps for domestic hot water heating	0.001%	0.001%	0.001%	0.000%	0.000%	0.002%	0.002%	**0.008%**
MID	**2020**	**2021**	**2022**	**2023**	**2024**	**2025 to 2029**	**2030 to 2034**	**Total**
% Residential customers adopting DMSHP in electric baseboard households	1.7%	1.7%	1.6%	1.6%	1.5%	4.1%	4.1%	**16.2%**
% Residential customers adopting heat pumps for space heating	0.04%	0.03%	0.03%	0.03%	0.03%	0.09%	0.08%	**0.33%**
% Residential customers adopting heat pumps for domestic hot water heating	0.00%	0.00%	0.00%	0.00%	0.00%	0.02%	0.02%	**0.06%**
% Commercial square footage adopting heat pumps for space heating	0.06%	0.05%	0.05%	0.04%	0.04%	0.11%	0.10%	**0.44%**
% Commercial customers adopting heat pumps for domestic hot water heating	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%	0.01%	**0.04%**
UPPER	**2020**	**2021**	**2022**	**2023**	**2024**	**2025 to 2029**	**2030 to 2034**	**Total**
% Residential customers adopting DMSHP in electric baseboard households	1.7%	1.7%	1.6%	1.6%	1.5%	4.1%	4.1%	**16.2%**
% Residential customers adopting heat pumps for space heating	0.53%	0.49%	0.47%	0.45%	0.42%	1.32%	1.30%	**4.96%**
% Residential customers adopting heat pumps for domestic hot water heating	0.06%	0.06%	0.06%	0.06%	0.06%	0.28%	0.28%	**0.85%**
% Commercial square footage adopting heat pumps for space heating	0.42%	0.39%	0.36%	0.34%	0.31%	0.86%	0.83%	**3.52%**
% Commercial customers adopting heat pumps for domestic hot water heating	0.04%	0.04%	0.04%	0.04%	0.04%	0.20%	0.20%	**0.59%**

Note: Unless otherwise noted, all results represent adoption by non-electric (e.g. oil and wood) space heating / domestic water heating customers.

Table F- 20: Fuel switching cumulative energy impacts (MID electricity rates, no carbon pricing), GWh

LOWER	2020	2021	2022	2023	2024	2029	2034
Energy reductions from electric resistance household adoption of DMSHP	-14	-28	-42	-56	-68	-103	-138
Energy increases from fuel switching (all sectors)	0	0	0	0	1	1	1
Net energy impact	-14	-28	-42	-55	-68	-102	-137
MID	**2020**	**2021**	**2022**	**2023**	**2024**	**2029**	**2034**
Energy reductions from electric resistance household adoption of DMSHP	-14	-28	-42	-56	-68	-103	-138
Energy increases from fuel switching (all sectors)	1	2	2	3	4	6	7
Net energy impact	-13	-27	-40	-53	-65	-97	-131
UPPER	**2020**	**2021**	**2022**	**2023**	**2024**	**2029**	**2034**
Energy reductions from electric resistance household adoption of DMSHP	-14	-28	-42	-56	-68	-103	-138
Energy increases from fuel switching (all sectors)	9	17	24	31	38	60	80
Net energy impact	-5	-12	-18	-24	-30	-43	-58

Table F- 21: Fuel switching cumulative demand impacts (MID electricity rates, no carbon pricing), MW

LOWER	2020	2021	2022	2023	2024	2029	2034
Demand reductions from electric resistance household adoption of DMSHP	-7	-14	-20	-27	-33	-50	-67
Demand increases from fuel switching (all sectors)	0	0	0	0	0	1	1
Net demand impact	-7	-13	-20	-27	-32	-49	-66
MID	**2020**	**2021**	**2022**	**2023**	**2024**	**2029**	**2034**
Demand reductions from electric resistance household adoption of DMSHP	-7	-14	-20	-27	-33	-50	-67
Demand increases from fuel switching (all sectors)	1	1	2	2	3	4	6
Net demand impact	-6	-12	-19	-25	-30	-45	-61
UPPER	**2020**	**2021**	**2022**	**2023**	**2024**	**2029**	**2034**
Demand reductions from electric resistance household adoption of DMSHP	-7	-14	-20	-27	-33	-50	-67
Demand increases from fuel switching (all sectors)	8	15	22	28	34	54	73
Net demand impact	1	1	1	1	1	4	6

Table F- 22: Fuel switching cumulative energy impacts by sector and technology (MID electricity rates, no carbon pricing), GWh

LOWER	2020	2021	2022	2023	2024	2029	2034
Residential customers adopting DMSHP	0.02	0.04	0.06	0.08	0.09	0.14	0.18
Residential customers adopting ASHP	0.04	0.07	0.10	0.12	0.15	0.28	0.39
Residential customers adopting domestic HW HP	0.00	0.00	0.00	0.01	0.01	0.02	0.02
Residential (TOTAL)	**0.06**	**0.12**	**0.16**	**0.21**	**0.25**	**0.43**	**0.58**
Commercial customers adopting DMSHP	0.07	0.12	0.17	0.22	0.26	0.37	0.47
Commercial customers adopting ASHP	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Commercial customers adopting domestic HW HP	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Commercial (TOTAL)	**0.07**	**0.12**	**0.17**	**0.22**	**0.26**	**0.37**	**0.47**
MID	**2020**	**2021**	**2022**	**2023**	**2024**	**2029**	**2034**
Residential customers adopting DMSHP	0.20	0.39	0.55	0.71	0.85	1.24	1.61
Residential customers adopting ASHP	0.17	0.32	0.44	0.56	0.68	1.24	1.75
Residential customers adopting domestic HW HP	0.01	0.02	0.03	0.04	0.05	0.09	0.09
Residential (TOTAL)	**0.38**	**0.72**	**1.02**	**1.30**	**1.57**	**2.57**	**3.45**
Commercial customers adopting DMSHP	0.52	0.97	1.37	1.74	2.07	2.99	3.85
Commercial customers adopting ASHP	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Commercial customers adopting domestic HW HP	0.00	0.00	0.00	0.01	0.01	0.01	0.01
Commercial (TOTAL)	**0.52**	**0.97**	**1.37**	**1.74**	**2.08**	**3.01**	**3.86**
UPPER	**2020**	**2021**	**2022**	**2023**	**2024**	**2029**	**2034**
Residential customers adopting DMSHP	3.35	6.46	9.42	12.24	14.83	22.07	29.24
Residential customers adopting ASHP	1.57	2.94	4.20	5.43	6.66	12.69	18.46
Residential customers adopting domestic HW HP	0.13	0.25	0.38	0.50	0.63	1.25	1.25
Residential (TOTAL)	**5.04**	**9.65**	**14.00**	**18.18**	**22.12**	**36.01**	**48.94**
Commercial customers adopting DMSHP	3.62	7.00	10.17	13.13	15.85	23.35	30.59
Commercial customers adopting ASHP	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Commercial customers adopting domestic HW HP	0.02	0.03	0.05	0.07	0.09	0.17	0.17
Commercial (TOTAL)	**3.64**	**7.04**	**10.22**	**13.20**	**15.93**	**23.52**	**30.76**

Note: All results represent adoption by non-electric (e.g. oil and wood) space heating / domestic water heating customers.

Table F- 23: Annual utility incentive costs (MID electricity rates, no carbon pricing)

MID	2020	2021	2022	2023	2024	2025-2029 Average	2030-2034 Average	Average per year
Residential	$180,000	$163,000	$150,000	$140,000	$130,000	$82,000	$78,000	$104,000
Commercial	$145,000	$127,000	$113,000	$104,000	$95,000	$52,000	$49,000	$73,000
Total	**$325,000**	**$290,000**	**$264,000**	**$244,000**	**$225,000**	**$134,000**	**$127,000**	**$177,000**
UPPER	**2020**	**2021**	**2022**	**2023**	**2024**	**2025-2029 Average**	**2030-2034 Average**	**Average per year**
Residential	$5,659,000	$5,283,000	$5,037,000	$4,808,000	$4,469,000	$2,727,000	$2,698,000	$3,492,000
Commercial	$2,053,000	$1,916,000	$1,796,000	$1,681,000	$1,545,000	$867,000	$837,000	$1,167,000
Total	**$7,712,000**	**$7,200,000**	**$6,832,000**	**$6,489,000**	**$6,014,000**	**$3,594,000**	**$3,535,000**	**$4,660,000**

SENSITIVITY ANALYSIS: HIGH ELECTRICITY RATES

This analysis assumed electricity rates at the HIGH rate scenario and no carbon pricing applied to oil rates.

Table F- 24: Percent of all customers adopting heat pump technologies (HIGH electricity rates, no carbon pricing)

LOWER	2020	2021	2022	2023	2024	2025 to 2029	2030 to 2034	Total
% Residential customers adopting DMSHP in electric baseboard households	2.0%	2.1%	2.0%	1.9%	1.8%	4.9%	5.0%	**19.7%**
% Residential customers adopting heat pumps for space heating	0.001%	0.001%	0.001%	0.001%	0.001%	0.004%	0.004%	**0.014%**
% Residential customers adopting heat pumps for domestic hot water heating	0.001%	0.001%	0.001%	0.001%	0.001%	0.003%	0.003%	**0.009%**
% Commercial square footage adopting heat pumps for space heating	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	**0.001%**
% Commercial customers adopting heat pumps for domestic hot water heating	0.000%	0.000%	0.000%	0.000%	0.000%	0.002%	0.002%	**0.006%**
MID	**2020**	**2021**	**2022**	**2023**	**2024**	**2025 to 2029**	**2030 to 2034**	**Total**
% Residential customers adopting DMSHP in electric baseboard households	2.0%	2.1%	2.0%	1.9%	1.8%	4.9%	5.0%	**19.7%**
% Residential customers adopting heat pumps for space heating	0.01%	0.01%	0.01%	0.01%	0.01%	0.03%	0.03%	**0.12%**
% Residential customers adopting heat pumps for domestic hot water heating	0.00%	0.00%	0.00%	0.00%	0.00%	0.02%	0.02%	**0.05%**
% Commercial square footage adopting heat pumps for space heating	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	**0.01%**
% Commercial customers adopting heat pumps for domestic hot water heating	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%	0.01%	**0.03%**
UPPER	**2020**	**2021**	**2022**	**2023**	**2024**	**2025 to 2029**	**2030 to 2034**	**Total**
% Residential customers adopting DMSHP in electric baseboard households	2.0%	2.1%	2.0%	1.9%	1.8%	4.9%	5.0%	**19.7%**
% Residential customers adopting heat pumps for space heating	0.29%	0.25%	0.25%	0.24%	0.23%	0.69%	0.66%	**2.62%**
% Residential customers adopting heat pumps for domestic hot water heating	0.05%	0.05%	0.05%	0.05%	0.05%	0.25%	0.25%	**0.76%**
% Commercial square footage adopting heat pumps for space heating	0.05%	0.03%	0.03%	0.03%	0.02%	0.07%	0.06%	**0.27%**
% Commercial customers adopting heat pumps for domestic hot water heating	0.03%	0.03%	0.03%	0.03%	0.03%	0.16%	0.16%	**0.48%**

Note: Unless otherwise noted, all results represent adoption by non-electric (e.g. oil and wood) space heating / domestic water heating customers.

Table F- 25: Fuel switching cumulative energy impacts (HIGH electricity rates, no carbon pricing), GWh

LOWER	2020	2021	2022	2023	2024	2029	2034
Energy reductions from electric resistance household adoption of DMSHP	-17	-35	-52	-68	-83	-125	-168
Energy increases from fuel switching (all sectors)	0	0	0	0	0	0	0
Net energy impact	-17	-35	-52	-68	-83	-125	-168
MID	**2020**	**2021**	**2022**	**2023**	**2024**	**2029**	**2034**
Energy reductions from electric resistance household adoption of DMSHP	-17	-35	-52	-68	-83	-125	-168
Energy increases from fuel switching (all sectors)	0	0	0	0	1	1	1
Net energy impact	-17	-35	-52	-68	-83	-125	-167
UPPER	**2020**	**2021**	**2022**	**2023**	**2024**	**2029**	**2034**
Energy reductions from electric resistance household adoption of DMSHP	-17	-35	-52	-68	-83	-125	-168
Energy increases from fuel switching (all sectors)	3	5	7	10	12	18	24
Net energy impact	-15	-30	-45	-59	-72	-107	-144

Table F- 26: Fuel switching cumulative demand impacts (HIGH electricity rates, no carbon pricing), MW

LOWER	2020	2021	2022	2023	2024	2029	2034
Demand reductions from electric resistance household adoption of DMSHP	-8	-17	-25	-33	-40	-60	-81
Demand increases from fuel switching (all sectors)	0	0	0	0	0	0	0
Net demand impact	-8	-17	-25	-33	-40	-60	-81
MID	**2020**	**2021**	**2022**	**2023**	**2024**	**2029**	**2034**
Demand reductions from electric resistance household adoption of DMSHP	-8	-17	-25	-33	-40	-60	-81
Demand increases from fuel switching (all sectors)	0	0	0	0	1	1	1
Net demand impact	-8	-17	-25	-32	-40	-59	-79
UPPER	**2020**	**2021**	**2022**	**2023**	**2024**	**2029**	**2034**
Demand reductions from electric resistance household adoption of DMSHP	-8	-17	-25	-33	-40	-60	-81
Demand increases from fuel switching (all sectors)	3	6	8	11	13	21	27
Net demand impact	-5	-11	-17	-22	-27	-40	-53

SENSITIVITY ANALYSIS: LOW ELECTRICITY RATES

This analysis assumed electricity rates at the LOW rate scenario and no carbon pricing applied to oil rates.

Table F- 27: Percent of all customers adopting heat pump technologies (LOW electricity rates, no carbon pricing)

LOWER	2020	2021	2022	2023	2024	2025 to 2029	2030 to 2034	Total
% Residential customers adopting DMSHP in electric baseboard households	1.3%	1.3%	1.3%	1.2%	1.1%	3.2%	3.2%	**12.8%**
% Residential customers adopting heat pumps for space heating	0.016%	0.015%	0.015%	0.015%	0.014%	0.057%	0.055%	**0.187%**
% Residential customers adopting heat pumps for domestic hot water heating	0.001%	0.001%	0.001%	0.001%	0.001%	0.004%	0.004%	**0.013%**
% Commercial square footage adopting heat pumps for space heating	0.026%	0.025%	0.024%	0.023%	0.021%	0.056%	0.054%	**0.229%**
% Commercial customers adopting heat pumps for domestic hot water heating	0.001%	0.001%	0.001%	0.001%	0.001%	0.003%	0.003%	**0.010%**
MID	**2020**	**2021**	**2022**	**2023**	**2024**	**2025 to 2029**	**2030 to 2034**	**Total**
% Residential customers adopting DMSHP in electric baseboard households	1.3%	1.3%	1.3%	1.2%	1.1%	3.2%	3.2%	**12.8%**
% Residential customers adopting heat pumps for space heating	0.09%	0.09%	0.09%	0.09%	0.08%	0.31%	0.30%	**1.05%**
% Residential customers adopting heat pumps for domestic hot water heating	0.00%	0.00%	0.00%	0.00%	0.00%	0.02%	0.02%	**0.07%**
% Commercial square footage adopting heat pumps for space heating	0.15%	0.15%	0.15%	0.14%	0.13%	0.35%	0.34%	**1.40%**
% Commercial customers adopting heat pumps for domestic hot water heating	0.00%	0.00%	0.00%	0.00%	0.00%	0.02%	0.02%	**0.05%**
UPPER	**2020**	**2021**	**2022**	**2023**	**2024**	**2025 to 2029**	**2030 to 2034**	**Total**
% Residential customers adopting DMSHP in electric baseboard households	1.3%	1.3%	1.3%	1.2%	1.1%	3.2%	3.2%	**12.8%**
% Residential customers adopting heat pumps for space heating	0.87%	0.86%	0.84%	0.81%	0.76%	2.48%	2.45%	**9.07%**
% Residential customers adopting heat pumps for domestic hot water heating	0.06%	0.06%	0.06%	0.06%	0.06%	0.31%	0.31%	**0.93%**
% Commercial square footage adopting heat pumps for space heating	0.60%	0.59%	0.58%	0.55%	0.51%	1.41%	1.39%	**5.64%**
% Commercial customers adopting heat pumps for domestic hot water heating	0.05%	0.05%	0.05%	0.05%	0.05%	0.23%	0.23%	**0.70%**

Note: Unless otherwise noted, all results represent adoption by non-electric (e.g. oil and wood) space heating / domestic water heating customers.

Table F- 28: Fuel switching cumulative energy impacts (LOW electricity rates, no carbon pricing), GWh

LOWER	2020	2021	2022	2023	2024	2029	2034
Energy reductions from electric resistance household adoption of DMSHP	-11	-23	-33	-44	-54	-81	-109
Energy increases from fuel switching (all sectors)	0	1	1	2	2	4	5
Net energy impact	-11	-22	-32	-42	-51	-77	-104
MID	**2020**	**2021**	**2022**	**2023**	**2024**	**2029**	**2034**
Energy reductions from electric resistance household adoption of DMSHP	-11	-23	-33	-44	-54	-81	-109
Energy increases from fuel switching (all sectors)	3	5	8	10	12	20	27
Net energy impact	-9	-17	-26	-34	-42	-61	-81
UPPER	**2020**	**2021**	**2022**	**2023**	**2024**	**2029**	**2034**
Energy reductions from electric resistance household adoption of DMSHP	-11	-23	-33	-44	-54	-81	-109
Energy increases from fuel switching (all sectors)	14	28	42	56	68	111	153
Net energy impact	3	6	9	12	15	30	45

Table F- 29: Fuel switching cumulative demand impacts (LOW electricity rates, no carbon pricing), MW

LOWER	2020	2021	2022	2023	2024	2029	2034
Demand reductions from electric resistance household adoption of DMSHP	-5	-11	-16	-21	-26	-39	-52
Demand increases from fuel switching (all sectors)	0	1	1	1	2	3	4
Net demand impact	-5	-10	-15	-20	-24	-36	-48
MID	**2020**	**2021**	**2022**	**2023**	**2024**	**2029**	**2034**
Demand reductions from electric resistance household adoption of DMSHP	-5	-11	-16	-21	-26	-39	-52
Demand increases from fuel switching (all sectors)	2	4	6	8	10	16	23
Net demand impact	-3	-7	-10	-13	-16	-23	-29
UPPER	**2020**	**2021**	**2022**	**2023**	**2024**	**2029**	**2034**
Demand reductions from electric resistance household adoption of DMSHP	-5	-11	-16	-21	-26	-39	-52
Demand increases from fuel switching (all sectors)	13	26	39	51	63	104	145
Net demand impact	8	15	23	30	37	65	93

SENSITIVITY ANALYSIS: CARBON PRICING, FEDERAL BACKSTOP

This analysis applied the federal backstop carbon pricing plan carbon levy to oil rates. Electricity rates are assumed at the MID rate scenario.

Table F- 30: Percent of all customers adopting heat pump technologies (MID electricity rates, federal backstop carbon pricing)

LOWER	2020	2021	2022	2023	2024	2025 to 2029	2030 to 2034	Total
% Residential customers adopting DMSHP in electric baseboard households	1.7%	1.7%	1.6%	1.6%	1.5%	4.1%	4.1%	**16.2%**
% Residential customers adopting heat pumps for space heating	0.013%	0.012%	0.012%	0.011%	0.011%	0.043%	0.041%	**0.144%**
% Residential customers adopting heat pumps for domestic hot water heating	0.001%	0.001%	0.001%	0.001%	0.001%	0.005%	0.005%	**0.016%**
% Commercial square footage adopting heat pumps for space heating	0.018%	0.017%	0.015%	0.014%	0.013%	0.036%	0.034%	**0.146%**
% Commercial customers adopting heat pumps for domestic hot water heating	0.001%	0.001%	0.001%	0.001%	0.001%	0.004%	0.004%	**0.011%**
MID	**2020**	**2021**	**2022**	**2023**	**2024**	**2025 to 2029**	**2030 to 2034**	**Total**
% Residential customers adopting DMSHP in electric baseboard households	1.7%	1.7%	1.6%	1.6%	1.5%	4.1%	4.1%	**16.2%**
% Residential customers adopting heat pumps for space heating	0.08%	0.08%	0.08%	0.07%	0.07%	0.24%	0.24%	**0.86%**
% Residential customers adopting heat pumps for domestic hot water heating	0.01%	0.01%	0.01%	0.01%	0.01%	0.03%	0.03%	**0.09%**
% Commercial square footage adopting heat pumps for space heating	0.12%	0.11%	0.10%	0.10%	0.09%	0.24%	0.23%	**1.00%**
% Commercial customers adopting heat pumps for domestic hot water heating	0.00%	0.00%	0.00%	0.00%	0.00%	0.02%	0.02%	**0.06%**
UPPER	**2020**	**2021**	**2022**	**2023**	**2024**	**2025 to 2029**	**2030 to 2034**	**Total**
% Residential customers adopting DMSHP in electric baseboard households	1.7%	1.7%	1.6%	1.6%	1.5%	4.1%	4.1%	**16.2%**
% Residential customers adopting heat pumps for space heating	0.83%	0.81%	0.78%	0.74%	0.70%	2.26%	2.22%	**8.35%**
% Residential customers adopting heat pumps for domestic hot water heating	0.07%	0.07%	0.07%	0.07%	0.07%	0.36%	0.35%	**1.07%**
% Commercial square footage adopting heat pumps for space heating	0.55%	0.53%	0.51%	0.48%	0.44%	1.24%	1.22%	**4.98%**
% Commercial customers adopting heat pumps for domestic hot water heating	0.05%	0.05%	0.05%	0.05%	0.05%	0.26%	0.26%	**0.78%**

Note: Unless otherwise noted, all results represent adoption by non-electric (e.g. oil and wood) space heating / domestic water heating customers.

Table F- 31: Fuel switching cumulative energy impacts (MID electricity rates, federal backstop carbon pricing), GWh

LOWER	2020	2021	2022	2023	2024	2029	2034
Energy reductions from electric resistance household adoption of DMSHP	-14	-28	-42	-56	-68	-103	-138
Energy increases from fuel switching (all sectors)	0	1	1	1	2	3	3
Net energy impact	-14	-28	-41	-55	-67	-100	-135
MID	**2020**	**2021**	**2022**	**2023**	**2024**	**2029**	**2034**
Energy reductions from electric resistance household adoption of DMSHP	-14	-28	-42	-56	-68	-103	-138
Energy increases from fuel switching (all sectors)	2	4	6	7	9	15	20
Net energy impact	-12	-24	-37	-48	-59	-88	-118
UPPER	**2020**	**2021**	**2022**	**2023**	**2024**	**2029**	**2034**
Energy reductions from electric resistance household adoption of DMSHP	-14	-28	-42	-56	-68	-103	-138
Energy increases from fuel switching (all sectors)	13	26	38	50	61	99	135
Net energy impact	-1	-2	-4	-5	-7	-4	-3

Table F- 32: Fuel switching cumulative demand impacts (MID electricity rates, federal backstop carbon pricing), MW

LOWER	2020	2021	2022	2023	2024	2029	2034
Demand reductions from electric resistance household adoption of DMSHP	-7	-14	-20	-27	-33	-50	-67
Demand increases from fuel switching (all sectors)	0	1	1	1	1	2	3
Net demand impact	-7	-13	-20	-26	-32	-47	-63
MID	**2020**	**2021**	**2022**	**2023**	**2024**	**2029**	**2034**
Demand reductions from electric resistance household adoption of DMSHP	-7	-14	-20	-27	-33	-50	-67
Demand increases from fuel switching (all sectors)	2	3	5	6	7	12	17
Net demand impact	-5	-10	-16	-21	-25	-37	-50
UPPER	**2020**	**2021**	**2022**	**2023**	**2024**	**2029**	**2034**
Demand reductions from electric resistance household adoption of DMSHP	-7	-14	-20	-27	-33	-50	-67
Demand increases from fuel switching (all sectors)	12	24	36	47	57	93	129
Net demand impact	5	11	15	20	24	44	62

SENSITIVITY ANALYSIS: CARBON PRICING, SOCIAL COST OF CARBON

This analysis applied a social cost of carbon levy to oil rates. Electricity rates are assumed at the MID rate scenario.

Table F- 33: Percent of all customers adopting heat pump technologies (MID electricity rates, SCC carbon pricing)

LOWER	2020	2021	2022	2023	2024	2025 to 2029	2030 to 2034	Total
% Residential customers adopting DMSHP in electric baseboard households	1.7%	1.7%	1.6%	1.6%	1.5%	4.1%	4.1%	**16.2%**
% Residential customers adopting heat pumps for space heating	0.086%	0.086%	0.086%	0.086%	0.086%	0.391%	0.436%	**1.256%**
% Residential customers adopting heat pumps for domestic hot water heating	0.003%	0.003%	0.003%	0.003%	0.003%	0.017%	0.018%	**0.050%**
% Commercial square footage adopting heat pumps for space heating	0.102%	0.100%	0.098%	0.095%	0.090%	0.269%	0.298%	**1.052%**
% Commercial customers adopting heat pumps for domestic hot water heating	0.002%	0.002%	0.002%	0.002%	0.003%	0.013%	0.015%	**0.041%**
MID	**2020**	**2021**	**2022**	**2023**	**2024**	**2025 to 2029**	**2030 to 2034**	**Total**
% Residential customers adopting DMSHP in electric baseboard households	1.7%	1.7%	1.6%	1.6%	1.5%	4.1%	4.1%	**16.2%**
% Residential customers adopting heat pumps for space heating	0.37%	0.37%	0.37%	0.37%	0.35%	1.39%	1.49%	**4.72%**
% Residential customers adopting heat pumps for domestic hot water heating	0.01%	0.01%	0.01%	0.02%	0.02%	0.08%	0.09%	**0.25%**
% Commercial square footage adopting heat pumps for space heating	0.36%	0.36%	0.35%	0.34%	0.31%	0.91%	0.96%	**3.58%**
% Commercial customers adopting heat pumps for domestic hot water heating	0.01%	0.01%	0.01%	0.01%	0.01%	0.07%	0.07%	**0.20%**
UPPER	**2020**	**2021**	**2022**	**2023**	**2024**	**2025 to 2029**	**2030 to 2034**	**Total**
% Residential customers adopting DMSHP in electric baseboard households	1.7%	1.7%	1.6%	1.6%	1.5%	4.1%	4.1%	**16.2%**
% Residential customers adopting heat pumps for space heating	1.55%	1.53%	1.51%	1.46%	1.38%	4.50%	4.62%	**16.54%**
% Residential customers adopting heat pumps for domestic hot water heating	0.12%	0.12%	0.12%	0.12%	0.12%	0.64%	0.67%	**1.92%**
% Commercial square footage adopting heat pumps for space heating	0.79%	0.77%	0.76%	0.72%	0.67%	1.89%	1.92%	**7.52%**
% Commercial customers adopting heat pumps for domestic hot water heating	0.10%	0.10%	0.10%	0.10%	0.10%	0.53%	0.55%	**1.58%**

Note: Unless otherwise noted, all results represent adoption by non-electric (e.g. oil and wood)space heating / domestic water heating customers.

Table F- 34: Fuel switching cumulative energy impacts (MID electricity rates, SCC carbon pricing), GWh

LOWER	2020	2021	2022	2023	2024	2029	2034
Energy reductions from electric resistance household adoption of DMSHP	-14	-28	-42	-56	-68	-103	-138
Energy increases from fuel switching (all sectors)	2	5	7	9	11	21	32
Net energy impact	-12	-24	-35	-47	-57	-82	-106
MID	**2020**	**2021**	**2022**	**2023**	**2024**	**2029**	**2034**
Energy reductions from electric resistance household adoption of DMSHP	-14	-28	-42	-56	-68	-103	-138
Energy increases from fuel switching (all sectors)	8	16	24	31	39	68	99
Net energy impact	-6	-12	-19	-24	-29	-35	-39
UPPER	**2020**	**2021**	**2022**	**2023**	**2024**	**2029**	**2034**
Energy reductions from electric resistance household adoption of DMSHP	-14	-28	-42	-56	-68	-103	-138
Energy increases from fuel switching (all sectors)	22	44	66	87	107	177	246
Net energy impact	8	16	24	31	39	74	108

Table F- 35: Fuel switching demand impacts (MID electricity rates, SCC carbon pricing), MW

LOWER	2020	2021	2022	2023	2024	2029	2034
Demand reductions from electric resistance household adoption of DMSHP	-7	-14	-20	-27	-33	-50	-67
Demand increases from fuel switching (all sectors)	2	4	6	8	10	19	30
Net demand impact	-5	-10	-14	-19	-23	-30	-37
MID	**2020**	**2021**	**2022**	**2023**	**2024**	**2029**	**2034**
Demand reductions from electric resistance household adoption of DMSHP	-7	-14	-20	-27	-33	-50	-67
Demand increases from fuel switching (all sectors)	7	14	21	28	35	63	93
Net demand impact	0	0	1	1	2	13	26
UPPER	**2020**	**2021**	**2022**	**2023**	**2024**	**2029**	**2034**
Demand reductions from electric resistance household adoption of DMSHP	-7	-14	-20	-27	-33	-50	-67
Demand increases from fuel switching (all sectors)	22	43	64	84	104	172	242
Net demand impact	15	29	43	57	71	123	176

SENSITIVITY ANALYSIS: TRC SCREENING

This analysis screened out measures that did not pass TRC screening. Electricity rates are assumed at the MID rate scenario and no carbon pricing is applied to oil rates.

Table F- 36: Percent of all customers adopting heat pump technologies (MID electricity rates, no carbon pricing, TRC screening)

LOWER	2020	2021	2022	2023	2024	2025 to 2029	2030 to 2034	Total
% Residential customers adopting DMSHP in electric baseboard households	1.7%	1.7%	1.6%	1.6%	1.5%	4.1%	4.1%	**16.2%**
% Residential customers adopting heat pumps for space heating	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	**0.000%**
% Residential customers adopting heat pumps for domestic hot water heating	0.001%	0.001%	0.001%	0.001%	0.001%	0.004%	0.004%	**0.011%**
% Commercial square footage adopting heat pumps for space heating	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	**0.000%**
% Commercial customers adopting heat pumps for domestic hot water heating	0.000%	0.000%	0.000%	0.000%	0.000%	0.002%	0.002%	**0.006%**
MID	**2020**	**2021**	**2022**	**2023**	**2024**	**2025 to 2029**	**2030 to 2034**	**Total**
% Residential customers adopting DMSHP in electric baseboard households	1.7%	1.7%	1.6%	1.6%	1.5%	4.1%	4.1%	**16.2%**
% Residential customers adopting heat pumps for space heating	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	**0.00%**
% Residential customers adopting heat pumps for domestic hot water heating	0.004%	0.004%	0.004%	0.004%	0.004%	0.020%	0.020%	**0.06%**
% Commercial square footage adopting heat pumps for space heating	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	**0.00%**
% Commercial customers adopting heat pumps for domestic hot water heating	0.002%	0.002%	0.002%	0.002%	0.002%	0.011%	0.011%	**0.03%**
UPPER	**2020**	**2021**	**2022**	**2023**	**2024**	**2025 to 2029**	**2030 to 2034**	**Total**
% Residential customers adopting DMSHP in electric baseboard households	1.7%	1.7%	1.6%	1.6%	1.5%	4.1%	4.1%	**16.2%**
% Residential customers adopting heat pumps for space heating	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	**0.00%**
% Residential customers adopting heat pumps for domestic hot water heating	0.058%	0.057%	0.057%	0.056%	0.057%	0.283%	0.281%	**0.85%**
% Commercial square footage adopting heat pumps for space heating	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	**0.00%**
% Commercial customers adopting heat pumps for domestic hot water heating	0.029%	0.028%	0.028%	0.028%	0.028%	0.139%	0.138%	**0.42%**

Note: Unless otherwise noted, all results represent adoption by non-electric (e.g. oil and wood) space heating / domestic water heating customers.

Table F- 37: Fuel switching cumulative energy impacts (MID electricity rates, no carbon pricing, TRC screening), GWh

LOWER	2020	2021	2022	2023	2024	2029	2034
Energy reductions from electric resistance household adoption of DMSHP	-14	-28	-42	-56	-68	-103	-138
Energy increases from fuel switching (all sectors)	0	0	0	0	0	0	0
Net energy impact	-14	-28	-42	-56	-68	-103	-138
MID	**2020**	**2021**	**2022**	**2023**	**2024**	**2029**	**2034**
Energy reductions from electric resistance household adoption of DMSHP	-14	-28	-42	-56	-68	-103	-138
Energy increases from fuel switching (all sectors)	0	0	0	0	0	0	0
Net energy impact	-14	-28	-42	-56	-68	-103	-138
UPPER	**2020**	**2021**	**2022**	**2023**	**2024**	**2029**	**2034**
Energy reductions from electric resistance household adoption of DMSHP	-14	-28	-42	-56	-68	-103	-138
Energy increases from fuel switching (all sectors)	0	0	0	1	1	1	1
Net energy impact	-14	-28	-42	-55	-67	-102	-137

Table F- 38: Fuel switching cumulative demand impacts (MID electricity rates, no carbon pricing, TRC screening), MW

LOWER	2020	2021	2022	2023	2024	2029	2034
Demand reductions from electric resistance household adoption of DMSHP	-7	-14	-20	-27	-33	-50	-67
Demand increases from fuel switching (all sectors)	0	0	0	0	0	0	0
Net demand impact	-7	-14	-20	-27	-33	-50	-67
MID	**2020**	**2021**	**2022**	**2023**	**2024**	**2029**	**2034**
Demand reductions from electric resistance household adoption of DMSHP	-7	-14	-20	-27	-33	-50	-67
Demand increases from fuel switching (all sectors)	0	0	0	0	0	0	0
Net demand impact	-7	-14	-20	-27	-33	-50	-66
UPPER	**2020**	**2021**	**2022**	**2023**	**2024**	**2029**	**2034**
Demand reductions from electric resistance household adoption of DMSHP	-7	-14	-20	-27	-33	-50	-67
Demand increases from fuel switching (all sectors)	0	0	0	0	0	0	0
Net demand impact	-7	-14	-20	-27	-33	-49	-66

ELECTRIC VEHICLE ADOPTION DETAILED RESULTS TABLES

Table F- 39: Adoption Under Baseline Scenario

			2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Annual Vehicle Sales	LDV Personal	PHEVs	76	178	200	278	347	542	806	993	1,210	1,415	1,615	1,810	1,994	2,157	2,328	2,438
		BEVs	80	123	210	358	505	559	606	682	738	774	803	829	844	858	869	861
		EVs	**156**	**301**	**410**	**636**	**853**	**1,100**	**1,412**	**1,675**	**1,948**	**2,189**	**2,418**	**2,638**	**2,838**	**3,015**	**3,197**	**3,299**
	LDV Commercial	PHEVs	20	34	49	66	108	149	195	244	329	412	499	603	702	789	891	953
		BEVs	3	9	17	27	45	68	103	142	195	249	302	355	402	446	489	510
		EVs	**23**	**43**	**66**	**94**	**153**	**217**	**299**	**386**	**524**	**661**	**801**	**958**	**1,104**	**1,235**	**1,381**	**1,463**
	MDV	BEVs	0	1	2	9	21	44	77	117	161	212	268	331	396	457	550	617
	HDV	BEVs	-	-	-	0	0	1	3	6	10	14	19	28	37	46	55	64
	Bus	BEVs	0	1	1	3	4	6	9	12	15	18	22	25	29	33	37	40
	Total	EVs	180	345	479	741	1,031	1,369	1,800	2,196	2,658	3,094	3,528	3,981	4,405	4,786	5,220	5,484
Cumulative Vehicle Sales	LDV Personal	PHEVs	122	300	501	778	1,126	1,667	2,473	3,466	4,676	6,091	7,706	9,515	11,509	13,666	15,995	18,432
		BEVs	121	244	454	811	1,317	1,875	2,481	3,163	3,902	4,676	5,479	6,308	7,152	8,010	8,879	9,740
		EVs	**243**	**544**	**954**	**1,590**	**2,442**	**3,542**	**4,954**	**6,629**	**8,577**	**10,767**	**13,185**	**15,823**	**18,662**	**21,676**	**24,874**	**28,173**
	LDV Commercial	PHEVs	20	54	103	169	277	426	621	865	1,194	1,606	2,106	2,709	3,410	4,199	5,091	6,044
		BEVs	3	12	28	56	101	169	272	414	609	858	1,159	1,515	1,917	2,363	2,852	3,362
		EVs	**23**	**66**	**131**	**225**	**378**	**595**	**894**	**1,279**	**1,803**	**2,464**	**3,265**	**4,223**	**5,327**	**6,562**	**7,943**	**9,406**
	MDV	BEVs	0	1	4	13	34	78	155	273	434	646	914	1,245	1,641	2,098	2,649	3,266
	HDV	BEVs	-	-	-	0	0	1	5	11	21	35	54	82	120	166	221	285
	Bus	BEVs	0	1	2	5	9	16	25	36	51	69	90	116	145	178	215	255
	Total	EVs	267	612	1,091	1,832	2,863	4,233	6,033	8,228	10,886	13,981	17,508	21,489	25,894	30,680	35,901	41,385
% Annual Sales	LDV Personal	PHEVs	0%	1%	1%	1%	1%	2%	3%	3%	4%	5%	5%	6%	6%	7%	7%	7%
		BEVs	0%	0%	1%	1%	2%	2%	2%	2%	3%	3%	3%	3%	3%	3%	3%	3%
		EVs	**1%**	**1%**	**2%**	**2%**	**3%**	**4%**	**5%**	**6%**	**7%**	**7%**	**8%**	**8%**	**9%**	**9%**	**10%**	**10%**
	LDV Commercial	PHEVs	0%	0%	0%	1%	1%	1%	2%	2%	3%	3%	4%	5%	5%	6%	6%	7%
		BEVs	0%	0%	0%	0%	0%	1%	1%	1%	2%	2%	2%	3%	3%	3%	3%	4%
		EVs	**0%**	**0%**	**1%**	**1%**	**1%**	**2%**	**3%**	**3%**	**4%**	**5%**	**6%**	**7%**	**8%**	**9%**	**10%**	**11%**
	MDV	BEVs	0%	0%	0%	0%	1%	2%	3%	5%	7%	9%	11%	13%	15%	17%	20%	22%
	HDV	BEVs	0%	0%	0%	0%	0%	0%	1%	2%	3%	4%	5%	7%	10%	12%	14%	16%
	Bus	BEVs	0%	1%	1%	2%	4%	6%	8%	10%	12%	15%	17%	20%	23%	25%	27%	29%
Energy Consumption (GWh)	LDV Personal	PHEVs	0.23	0.57	0.96	1.51	2.22	3.32	4.97	7.04	9.59	12.60	16.05	19.96	24.29	28.99	34.10	39.45
		BEVs	0.46	0.94	1.75	3.17	5.21	7.49	10.01	12.85	15.94	19.22	22.65	26.21	29.86	33.58	37.38	41.15
		EVs	**0.69**	**1.51**	**2.71**	**4.68**	**7.43**	**10.81**	**14.98**	**19.88**	**25.53**	**31.82**	**38.70**	**46.17**	**54.14**	**62.58**	**71.48**	**80.60**
	LDV Commercial	PHEVs	0.06	0.15	0.30	0.50	0.84	1.32	1.97	2.78	3.91	5.34	7.08	9.21	11.69	14.50	17.68	21.10
		BEVs	0.02	0.06	0.16	0.32	0.61	1.05	1.73	2.68	4.01	5.74	7.85	10.36	13.21	16.38	19.87	23.51
		EVs	**0.07**	**0.22**	**0.46**	**0.82**	**1.44**	**2.37**	**3.70**	**5.46**	**7.92**	**11.08**	**14.93**	**19.56**	**24.90**	**30.88**	**37.55**	**44.61**
	MDV	BEVs	0.01	0.03	0.09	0.28	0.76	1.76	3.50	6.13	9.76	14.54	20.57	28.01	36.93	47.21	59.59	73.48
	HDV	BEVs	-	-	-	0.00	0.02	0.22	0.76	1.78	3.37	5.67	8.78	13.37	19.43	26.95	35.91	46.32
	Bus	BEVs	0.02	0.07	0.18	0.40	0.75	1.28	1.99	2.92	4.10	5.56	7.31	9.37	11.74	14.42	17.39	20.65
	Total	EVs	1	2	3	6	10	16	25	36	51	69	90	116	147	182	222	266

Table F- 40: Adoption Under the sample $5M Investment Scenario

			2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Annual Vehicle Sales	LDV Personal	PHEVs	76	210	270	432	557	829	1,121	1,202	1,345	1,743	2,075	4,415	5,470	6,262	7,013	7,536
		BEVs	79	157	320	655	1,140	1,685	2,536	3,540	4,410	5,983	7,301	5,606	5,249	5,097	5,015	4,862
		EVs	**156**	**367**	**589**	**1,087**	**1,697**	**2,514**	**3,657**	**4,742**	**5,755**	**7,726**	**9,377**	**10,020**	**10,719**	**11,359**	**12,029**	**12,398**
	LDV Commercial	PHEVs	20	41	70	114	215	340	502	687	973	1,467	1,971	2,410	2,839	3,223	3,674	3,956
		BEVs	3	11	24	47	90	155	265	398	574	879	1,177	1,395	1,585	1,765	1,927	2,000
		EVs	**23**	**52**	**94**	**161**	**305**	**495**	**768**	**1,085**	**1,547**	**2,346**	**3,149**	**3,804**	**4,424**	**4,988**	**5,602**	**5,955**
	MDV	BEVs	0	1	2	9	22	45	80	122	169	224	286	356	430	500	607	685
	HDV	BEVs	-	-	-	0	0	1	3	6	10	15	20	30	40	51	61	71
	Bus	BEVs	0	1	1	3	4	7	9	12	15	19	23	27	32	36	41	45
	Total	EVs	**179**	**421**	**687**	**1,259**	**2,028**	**3,063**	**4,517**	**5,967**	**7,497**	**10,330**	**12,855**	**14,238**	**15,645**	**16,934**	**18,339**	**19,155**
Cumulative Vehicle Sales	LDV Personal	PHEVs	122	332	602	1,034	1,591	2,419	3,541	4,742	6,087	7,831	9,906	14,321	19,791	26,052	33,066	40,602
		BEVs	120	277	597	1,252	2,392	4,077	6,613	10,153	14,564	20,546	27,848	33,453	38,703	43,800	48,815	53,677
		EVs	**243**	**610**	**1,199**	**2,286**	**3,983**	**6,497**	**10,154**	**14,896**	**20,651**	**28,377**	**37,754**	**47,775**	**58,493**	**69,852**	**81,881**	**94,279**
	LDV Commercial	PHEVs	20	61	131	245	460	800	1,302	1,989	2,962	4,429	6,400	8,810	11,649	14,872	18,547	22,502
		BEVs	3	14	38	85	174	329	595	993	1,567	2,446	3,623	5,018	6,603	8,368	10,295	12,295
		EVs	**23**	**75**	**169**	**330**	**634**	**1,129**	**1,897**	**2,982**	**4,529**	**6,875**	**10,024**	**13,828**	**18,252**	**23,240**	**28,842**	**34,797**
	MDV	BEVs	0	1	4	13	34	80	160	281	450	674	960	1,315	1,746	2,246	2,853	3,539
	HDV	BEVs	-	-	-	0	0	1	5	11	22	37	57	87	128	178	239	310
	Bus	BEVs	0	1	2	5	9	16	25	37	52	71	94	122	153	190	230	275
	Total	EVs	**266**	**687**	**1,374**	**2,634**	**4,661**	**7,724**	**12,240**	**18,207**	**25,704**	**36,034**	**48,889**	**63,127**	**78,772**	**95,706**	**114,045**	**133,200**
% Annual Sales	LDV Personal	PHEVs	0%	1%	1%	2%	2%	3%	4%	4%	5%	6%	7%	14%	17%	19%	21%	23%
		BEVs	0%	1%	1%	3%	4%	6%	9%	12%	15%	20%	24%	18%	17%	16%	15%	15%
		EVs	**1%**	**1%**	**2%**	**4%**	**6%**	**9%**	**13%**	**17%**	**20%**	**26%**	**31%**	**32%**	**34%**	**35%**	**36%**	**37%**
	LDV Commercial	PHEVs	0%	0%	1%	1%	2%	3%	4%	6%	8%	12%	15%	18%	21%	23%	26%	29%
		BEVs	0%	0%	0%	0%	1%	1%	2%	3%	5%	7%	9%	11%	12%	13%	14%	15%
		EVs	**0%**	**0%**	**1%**	**1%**	**3%**	**4%**	**6%**	**9%**	**12%**	**19%**	**24%**	**29%**	**33%**	**36%**	**40%**	**43%**
	MDV	BEVs	0%	0%	0%	0%	1%	2%	3%	5%	7%	9%	11%	14%	17%	19%	23%	25%
	HDV	BEVs	0%	0%	0%	0%	0%	0%	1%	2%	3%	4%	5%	8%	10%	13%	15%	17%
	Bus	BEVs	0%	1%	1%	2%	4%	6%	8%	10%	13%	16%	19%	22%	25%	27%	30%	33%
Energy Consumption (GWh)	LDV Personal	PHEVs	0.23	0.63	1.15	2.01	3.14	4.82	7.09	9.57	12.40	16.12	20.59	30.13	42.01	55.68	71.06	87.61
		BEVs	0.45	1.07	2.31	4.91	9.51	16.41	26.95	41.73	60.28	85.64	116.82	140.92	163.63	185.80	207.72	229.01
		EVs	**0.69**	**1.70**	**3.46**	**6.92**	**12.65**	**21.22**	**34.03**	**51.30**	**72.68**	**101.77**	**137.41**	**171.05**	**205.63**	**241.47**	**278.78**	**316.62**
	LDV Commercial	PHEVs	0.06	0.17	0.38	0.73	1.41	2.50	4.16	6.47	9.81	14.90	21.79	30.29	40.34	51.82	64.95	79.13
		BEVs	0.02	0.08	0.21	0.49	1.05	2.06	3.81	6.48	10.42	16.52	24.77	34.61	45.86	58.43	72.21	86.51
		EVs	**0.07**	**0.25**	**0.59**	**1.22**	**2.46**	**4.56**	**7.98**	**12.96**	**20.22**	**31.42**	**46.56**	**64.90**	**86.21**	**110.25**	**137.16**	**165.64**
	MDV	BEVs	0.01	0.03	0.09	0.29	0.78	1.80	3.59	6.33	10.13	15.17	21.59	29.60	39.28	50.53	64.19	79.62
	HDV	BEVs	-	-	-	0.00	0.03	0.22	0.79	1.84	3.51	5.94	9.25	14.18	20.77	29.00	38.88	50.44
	Bus	BEVs	0.02	0.07	0.19	0.40	0.76	1.29	2.03	3.00	4.23	5.77	7.63	9.85	12.42	15.35	18.64	22.25
	Total	EVs	**0.78**	**2.06**	**4.33**	**8.83**	**16.67**	**29.11**	**48.42**	**75.42**	**110.78**	**160.06**	**222.45**	**289.58**	**364.30**	**446.61**	**537.64**	**634.57**

Table F- 41: Adoption Under the sample $20M Investment Scenario

			2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Annual Vehicle Sales	LDV Personal	PHEVs	122	219	290	474	622	910	1,267	1,362	1,703	2,006	2,203	2,392	2,596	2,714	2,844	4,733
		BEVs	121	166	346	723	1,275	1,939	2,920	4,044	5,551	6,820	7,661	8,495	9,244	9,980	10,553	8,802
		EVs	**243**	**385**	**637**	**1,197**	**1,897**	**2,849**	**4,187**	**5,406**	**7,255**	**8,826**	**9,863**	**10,888**	**11,840**	**12,694**	**13,397**	**13,536**
	LDV Commercial	PHEVs	20	43	75	125	238	381	567	769	1,196	1,633	2,001	2,447	2,882	3,273	3,731	4,016
		BEVs	3	11	26	52	100	174	300	445	706	978	1,196	1,416	1,609	1,792	1,957	2,030
		EVs	**23**	**54**	**101**	**176**	**338**	**555**	**867**	**1,214**	**1,902**	**2,611**	**3,197**	**3,863**	**4,492**	**5,064**	**5,688**	**6,046**
	MDV	BEVs	0	1	2	9	22	45	80	122	169	224	286	356	430	500	607	685
	HDV	BEVs	-	-	-	0	0	1	3	6	10	15	20	30	40	51	61	71
	Bus	BEVs	0	1	1	3	4	7	9	12	15	19	23	27	32	36	41	45
	Total	EVs	**267**	**441**	**742**	**1,385**	**2,261**	**3,457**	**5,147**	**6,760**	**9,351**	**11,695**	**13,389**	**15,164**	**16,834**	**18,345**	**19,793**	**20,383**
Cumulative Vehicle Sales	LDV Personal	PHEVs	122	341	632	1,106	1,728	2,638	3,905	5,267	6,970	8,976	11,179	13,571	16,167	18,881	21,725	26,458
		BEVs	121	287	633	1,356	2,631	4,570	7,490	11,534	17,085	23,905	31,566	40,061	49,305	59,285	69,838	78,640
		EVs	**243**	**628**	**1,265**	**2,462**	**4,359**	**7,208**	**11,395**	**16,801**	**24,055**	**32,881**	**42,745**	**53,633**	**65,473**	**78,166**	**91,563**	**105,099**
	LDV Commercial	PHEVs	20	63	139	263	502	883	1,450	2,219	3,414	5,047	7,049	9,495	12,378	15,650	19,381	23,397
		BEVs	3	14	40	91	191	365	665	1,110	1,815	2,794	3,989	5,405	7,014	8,806	10,763	12,794
		EVs	**23**	**77**	**178**	**355**	**693**	**1,247**	**2,115**	**3,328**	**5,230**	**7,841**	**11,038**	**14,900**	**19,392**	**24,456**	**30,144**	**36,190**
	MDV	BEVs	0	1	4	13	34	80	160	281	450	674	960	1,315	1,746	2,246	2,853	3,539
	HDV	BEVs	-	-	-	0	0	1	5	11	22	37	57	87	128	178	239	310
	Bus	BEVs	0	1	2	5	9	16	25	37	52	71	94	122	153	190	230	275
	Total	EVs	**267**	**708**	**1,449**	**2,835**	**5,096**	**8,552**	**13,699**	**20,459**	**29,809**	**41,504**	**54,893**	**70,057**	**86,891**	**105,237**	**125,029**	**145,413**
% Annual Sales	LDV Personal	PHEVs	0%	1%	1%	2%	2%	3%	4%	5%	6%	7%	7%	8%	8%	8%	9%	14%
		BEVs	0%	1%	1%	3%	5%	7%	10%	14%	19%	23%	25%	27%	29%	31%	32%	27%
		EVs	**1%**	**2%**	**2%**	**4%**	**7%**	**10%**	**15%**	**19%**	**25%**	**29%**	**32%**	**35%**	**37%**	**39%**	**40%**	**41%**
	LDV Commercial	PHEVs	0%	0%	1%	1%	2%	3%	5%	6%	10%	13%	15%	19%	21%	24%	27%	29%
		BEVs	0%	0%	0%	0%	1%	1%	3%	4%	6%	8%	9%	11%	12%	13%	14%	15%
		EVs	**0%**	**1%**	**1%**	**2%**	**3%**	**5%**	**7%**	**10%**	**15%**	**21%**	**25%**	**29%**	**33%**	**37%**	**41%**	**44%**
	MDV	BEVs	0%	0%	0%	0%	1%	2%	3%	5%	7%	9%	11%	14%	17%	19%	23%	25%
	HDV	BEVs	0%	0%	0%	0%	0%	0%	1%	2%	3%	4%	5%	8%	10%	13%	15%	17%
	Bus	BEVs	0%	1%	1%	2%	4%	6%	8%	10%	13%	16%	19%	22%	25%	27%	30%	33%
Energy Consumption (GWh)	LDV Personal	PHEVs	0.23	0.65	1.21	2.15	3.42	5.25	7.82	10.63	14.22	18.51	23.25	28.45	34.12	40.09	46.37	56.81
		BEVs	0.46	1.11	2.45	5.32	10.46	18.41	30.55	47.44	70.80	99.73	132.46	169.00	209.02	252.45	298.62	337.20
		EVs	**0.69**	**1.76**	**3.66**	**7.47**	**13.88**	**23.66**	**38.37**	**58.07**	**85.02**	**118.23**	**155.71**	**197.45**	**243.14**	**292.53**	**344.99**	**394.01**
	LDV Commercial	PHEVs	0.06	0.18	0.40	0.78	1.53	2.77	4.64	7.22	11.32	16.99	23.99	32.61	42.82	54.47	67.81	82.20
		BEVs	0.02	0.08	0.23	0.53	1.16	2.28	4.26	7.25	12.09	18.88	27.26	37.25	48.67	61.43	75.42	89.94
		EVs	**0.07**	**0.26**	**0.63**	**1.31**	**2.69**	**5.05**	**8.90**	**14.47**	**23.41**	**35.87**	**51.24**	**69.86**	**91.49**	**115.90**	**143.22**	**172.14**
	MDV	BEVs	0.01	0.03	0.09	0.29	0.78	1.80	3.59	6.33	10.13	15.17	21.59	29.60	39.28	50.53	64.19	79.62
	HDV	BEVs	-	-	-	0.00	0.03	0.22	0.79	1.84	3.51	5.94	9.25	14.18	20.77	29.00	38.88	50.44
	Bus	BEVs	0.02	0.07	0.19	0.40	0.76	1.29	2.03	3.00	4.23	5.77	7.63	9.85	12.42	15.35	18.64	22.25
	Total	EVs	**0.79**	**2.12**	**4.56**	**9.48**	**18.13**	**32.03**	**53.68**	**83.71**	**126.30**	**180.97**	**245.43**	**320.95**	**407.09**	**503.32**	**609.92**	**718.46**

Table F- 42: Cumulative EV Sales by Lever Scenario

			2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Baseline		LDV Personal	243	544	954	1,590	2,442	3,542	4,954	6,629	8,577	10,767	13,185	15,823	18,662	21,676	24,874	28,173
		LDV Commercial	23	66	131	225	378	595	894	1,279	1,803	2,464	3,265	4,223	5,327	6,562	7,943	9,406
		MDV	0	1	4	13	34	78	155	273	434	646	914	1,245	1,641	2,098	2,649	3,266
		HDV	-	-	-	0	0	1	5	11	21	35	54	82	120	166	221	285
		Bus	0	1	2	5	9	16	25	36	51	69	90	116	145	178	215	255
		Total	**267**	**612**	**1,091**	**1,832**	**2,863**	**4,233**	**6,033**	**8,228**	**10,886**	**13,981**	**17,508**	**21,489**	**25,894**	**30,680**	**35,901**	**41,385**
DCFC	Low	LDV Personal	243	560	1,015	1,754	2,795	4,215	6,135	8,487	11,434	14,978	19,295	24,895	31,696	38,900	46,527	54,387
		LDV Commercial	23	68	141	250	436	712	1,108	1,641	2,421	3,476	4,887	6,886	9,490	12,403	15,659	19,111
		MDV	0	1	4	13	34	78	155	273	434	646	914	1,245	1,641	2,098	2,649	3,266
		HDV	-	-	-	0	0	1	5	11	21	35	54	82	120	166	221	285
		Bus	0	1	2	5	9	16	25	36	51	69	90	116	145	178	215	255
		Total	**266**	**630**	**1,162**	**2,022**	**3,274**	**5,022**	**7,428**	**10,447**	**14,361**	**19,204**	**25,240**	**33,224**	**43,092**	**53,745**	**65,271**	**77,304**
	High	LDV Personal	243	610	1,199	2,251	3,854	6,187	9,529	13,893	19,867	27,590	37,040	47,371	58,504	70,355	82,728	95,418
		LDV Commercial	23	75	169	324	610	1,063	1,752	2,724	4,273	6,514	9,536	13,153	17,319	21,980	27,191	32,714
		MDV	0	1	4	13	34	78	155	273	434	646	914	1,245	1,641	2,098	2,649	3,266
		HDV	-	-	-	0	0	1	5	11	21	35	54	82	120	166	221	285
		Bus	0	1	2	5	9	16	25	36	51	69	90	116	145	178	215	255
		Total	**266**	**687**	**1,374**	**2,592**	**4,507**	**7,346**	**11,465**	**16,937**	**24,645**	**34,854**	**47,635**	**61,967**	**77,729**	**94,777**	**113,003**	**131,939**
L2	Low	LDV Personal	244	554	988	1,679	2,630	3,921	5,665	7,821	10,434	13,491	17,068	21,190	26,017	31,136	36,559	42,151
		LDV Commercial	23	67	136	237	407	660	1,023	1,514	2,208	3,120	4,291	5,770	7,624	9,698	12,016	14,474
		MDV	0	1	4	13	34	78	155	273	434	646	914	1,245	1,641	2,098	2,649	3,266
		HDV	-	-	-	0	0	1	5	11	21	35	54	82	120	166	221	285
		Bus	0	1	2	5	9	16	25	36	51	69	90	116	145	178	215	255
		Total	**267**	**623**	**1,130**	**1,934**	**3,081**	**4,676**	**6,873**	**9,654**	**13,148**	**17,361**	**22,418**	**28,403**	**35,547**	**43,276**	**51,660**	**60,431**
	High	LDV Personal	244	580	1,083	1,933	3,167	5,001	7,679	11,236	15,811	21,445	28,478	37,040	47,847	59,315	71,409	83,859
		LDV Commercial	23	70	150	274	494	853	1,411	2,216	3,423	5,089	7,370	10,411	14,515	19,106	24,238	29,678
		MDV	0	1	4	13	34	78	155	273	434	646	914	1,245	1,641	2,098	2,649	3,266
		HDV	-	-	-	0	0	1	5	11	21	35	54	82	120	166	221	285
		Bus	0	1	2	5	9	16	25	36	51	69	90	116	145	178	215	255
		Total	**267**	**652**	**1,239**	**2,225**	**3,704**	**5,949**	**9,275**	**13,772**	**19,740**	**27,284**	**36,907**	**48,894**	**64,268**	**80,863**	**98,731**	**117,343**
Incentives	Low	LDV Personal	267	604	1,053	1,737	2,642	3,797	5,222	6,923	8,915	11,171	13,684	16,448	19,443	22,644	26,026	29,486
		LDV Commercial	41	109	202	325	511	765	1,111	1,548	2,133	2,825	3,672	4,695	5,886	7,227	8,734	10,336
		MDV	1	3	8	24	55	114	210	347	527	750	1,035	1,388	1,814	2,307	2,901	3,566
		HDV	-	-	0	0	1	2	7	14	25	40	60	90	130	180	240	309
		Bus	0	1	3	6	10	17	27	39	54	73	96	123	155	191	230	274
		Total	**309**	**717**	**1,266**	**2,091**	**3,219**	**4,695**	**6,576**	**8,871**	**11,654**	**14,859**	**18,547**	**22,745**	**27,428**	**32,549**	**38,131**	**43,970**
	High	LDV Personal	279	648	1,150	1,897	2,900	4,149	5,760	7,458	9,449	11,706	14,221	16,990	19,995	23,210	26,598	30,064
		LDV Commercial	50	137	263	424	672	995	1,427	1,954	2,634	3,326	4,173	5,196	6,386	7,728	9,235	10,837
		MDV	2	6	13	32	70	137	243	389	575	799	1,083	1,437	1,863	2,355	2,949	3,615
		HDV	-	0	0	0	1	3	8	16	27	42	62	92	132	182	242	311
		Bus	0	1	3	6	11	18	28	40	56	75	98	125	156	192	232	275
		Total	**332**	**793**	**1,428**	**2,360**	**3,653**	**5,302**	**7,465**	**9,858**	**12,741**	**15,947**	**19,637**	**23,840**	**28,532**	**33,668**	**39,255**	**45,101**

Table F- 43: Annual EV Energy Consumption (GWh) by Lever Scenario

			2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Baseline		LDV Personal	0.69	1.51	2.71	4.68	7.43	10.81	14.98	19.88	25.53	31.82	38.70	46.17	54.14	62.58	71.48	80.60
		LDV Commercial	0.07	0.22	0.46	0.82	1.44	2.37	3.70	5.46	7.92	11.08	14.93	19.56	24.90	30.88	37.55	44.61
		MDV	0.01	0.03	0.09	0.28	0.76	1.76	3.50	6.13	9.76	14.54	20.57	28.01	36.93	47.21	59.59	73.48
		HDV	-	-	-	0.00	0.02	0.22	0.76	1.78	3.37	5.67	8.78	13.37	19.43	26.95	35.91	46.32
		Bus	0.02	0.07	0.18	0.40	0.75	1.28	1.99	2.92	4.10	5.56	7.31	9.37	11.74	14.42	17.39	20.65
		Total	**0.79**	**1.83**	**3.44**	**6.19**	**10.41**	**16.43**	**24.92**	**36.18**	**50.70**	**68.66**	**90.29**	**116.47**	**147.13**	**182.04**	**221.93**	**265.67**
DCFC	Low	LDV Personal	0.69	1.56	2.90	5.21	8.65	13.44	20.06	27.86	37.52	48.87	62.68	80.85	102.71	125.29	148.75	172.53
		LDV Commercial	0.07	0.22	0.49	0.92	1.67	2.85	4.61	7.05	10.71	15.75	22.54	32.20	44.78	58.89	74.64	91.28
		MDV	0.01	0.03	0.09	0.28	0.76	1.76	3.50	6.13	9.76	14.54	20.57	28.01	36.93	47.21	59.59	73.48
		HDV	-	-	-	0.00	0.02	0.22	0.76	1.78	3.37	5.67	8.78	13.37	19.43	26.95	35.91	46.32
		Bus	0.02	0.07	0.18	0.40	0.75	1.28	1.99	2.92	4.10	5.56	7.31	9.37	11.74	14.42	17.39	20.65
		Total	**0.78**	**1.89**	**3.66**	**6.82**	**11.86**	**19.54**	**30.92**	**45.74**	**65.48**	**90.38**	**121.87**	**163.80**	**215.59**	**272.76**	**336.29**	**404.26**
	High	LDV Personal	0.69	1.70	3.46	6.80	12.21	20.21	31.93	47.81	70.01	99.09	135.02	174.66	217.67	263.84	307.59	350.48
		LDV Commercial	0.07	0.25	0.59	1.20	2.36	4.29	7.34	11.81	19.08	29.77	44.33	61.79	81.93	104.51	129.70	156.33
		MDV	0.01	0.03	0.09	0.28	0.76	1.76	3.50	6.13	9.76	14.54	20.57	28.01	36.93	47.21	59.59	73.48
		HDV	-	-	-	0.00	0.02	0.22	0.76	1.78	3.37	5.67	8.78	13.37	19.43	26.95	35.91	46.32
		Bus	0.02	0.07	0.18	0.40	0.75	1.28	1.99	2.92	4.10	5.56	7.31	9.37	11.74	14.42	17.39	20.65
		Total	**0.78**	**2.06**	**4.32**	**8.68**	**16.11**	**27.75**	**45.52**	**70.45**	**106.33**	**154.63**	**216.00**	**287.20**	**367.70**	**456.93**	**550.19**	**647.27**
L2	Low	LDV Personal	0.69	1.54	2.81	4.96	8.03	12.06	17.43	23.92	31.66	40.60	51.00	62.92	76.84	91.45	106.89	122.76
		LDV Commercial	0.07	0.22	0.47	0.87	1.56	2.63	4.25	6.50	9.76	14.11	19.75	26.89	35.85	45.90	57.11	68.96
		MDV	0.01	0.03	0.09	0.28	0.76	1.76	3.50	6.13	9.76	14.54	20.57	28.01	36.93	47.21	59.59	73.48
		HDV	-	-	-	0.00	0.02	0.22	0.76	1.78	3.37	5.67	8.78	13.37	19.43	26.95	35.91	46.32
		Bus	0.02	0.07	0.18	0.40	0.75	1.28	1.99	2.92	4.10	5.56	7.31	9.37	11.74	14.42	17.39	20.65
		Total	**0.79**	**1.87**	**3.56**	**6.52**	**11.13**	**17.94**	**27.93**	**41.25**	**58.66**	**80.49**	**107.41**	**140.56**	**180.79**	**225.93**	**276.90**	**332.18**
	High	LDV Personal	0.69	1.61	3.09	5.73	9.73	15.35	23.50	34.38	48.36	65.55	86.96	113.02	146.12	181.19	217.00	253.43
		LDV Commercial	0.07	0.23	0.53	1.01	1.90	3.43	5.91	9.60	15.27	23.22	34.20	48.89	68.73	90.96	115.78	142.01
		MDV	0.01	0.03	0.09	0.28	0.76	1.76	3.50	6.13	9.76	14.54	20.57	28.01	36.93	47.21	59.59	73.48
		HDV	-	-	-	0.00	0.02	0.22	0.76	1.78	3.37	5.67	8.78	13.37	19.43	26.95	35.91	46.32
		Bus	0.02	0.07	0.18	0.40	0.75	1.28	1.99	2.92	4.10	5.56	7.31	9.37	11.74	14.42	17.39	20.65
		Total	**0.79**	**1.95**	**3.88**	**7.43**	**13.17**	**22.03**	**35.66**	**54.81**	**80.87**	**114.54**	**157.82**	**212.66**	**282.95**	**360.74**	**445.67**	**535.89**
Incentives	Low	LDV Personal	0.79	1.76	3.11	5.30	8.27	11.81	15.99	20.95	26.71	33.17	40.31	48.11	56.51	65.44	74.84	84.38
		LDV Commercial	0.14	0.39	0.75	1.25	2.02	3.11	4.66	6.68	9.43	12.73	16.80	21.74	27.47	33.94	41.17	48.83
		MDV	0.02	0.07	0.19	0.53	1.24	2.56	4.72	7.81	11.85	16.87	23.28	31.23	40.81	51.90	65.26	80.24
		HDV	-	-	0.00	0.01	0.09	0.37	1.07	2.27	4.04	6.46	9.77	14.67	21.18	29.29	38.95	50.18
		Bus	0.02	0.09	0.21	0.45	0.84	1.40	2.16	3.16	4.41	5.94	7.80	10.00	12.55	15.44	18.65	22.16
		Total	**0.98**	**2.30**	**4.27**	**7.53**	**12.46**	**19.26**	**28.61**	**40.86**	**56.43**	**75.18**	**97.96**	**125.75**	**158.52**	**196.00**	**238.88**	**285.80**
	High	LDV Personal	0.85	1.92	3.47	5.90	9.25	13.04	17.77	22.68	28.40	34.83	41.96	49.75	58.16	67.12	76.51	86.06
		LDV Commercial	0.17	0.50	1.01	1.67	2.71	4.11	6.06	8.48	11.67	14.98	19.05	23.98	29.71	36.18	43.42	51.08
		MDV	0.04	0.13	0.29	0.72	1.57	3.09	5.47	8.76	12.94	17.97	24.37	32.33	41.91	52.99	66.36	81.33
		HDV	-	0.00	0.00	0.02	0.14	0.48	1.26	2.55	4.37	6.80	10.10	15.00	21.51	29.62	39.29	50.52
		Bus	0.03	0.10	0.23	0.49	0.88	1.47	2.25	3.26	4.52	6.05	7.91	10.11	12.66	15.54	18.76	22.27
		Total	**1.08**	**2.65**	**5.00**	**8.79**	**14.57**	**22.18**	**32.81**	**45.73**	**61.91**	**80.63**	**103.39**	**131.17**	**163.95**	**201.46**	**244.33**	**291.26**

Table F- 44: Cumulative EV Sales by Sensitivity Scenario

			2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Baseline		LDV Personal	243	544	954	1,590	2,442	3,542	4,954	6,629	8,577	10,767	13,185	15,823	18,662	21,676	24,874	28,173
		LDV Commercial	23	66	131	225	378	595	894	1,279	1,803	2,464	3,265	4,223	5,327	6,562	7,943	9,406
		MDV	0	1	4	13	34	78	155	273	434	646	914	1,245	1,641	2,098	2,649	3,266
		HDV	-	-	-	0	0	1	5	11	21	35	54	82	120	166	221	285
		Bus	0	1	2	5	9	16	25	36	51	69	90	116	145	178	215	255
		Total	**267**	**612**	**1,091**	**1,832**	**2,863**	**4,233**	**6,033**	**8,228**	**10,886**	**13,981**	**17,508**	**21,489**	**25,894**	**30,680**	**35,901**	**41,385**
Battery Costs	Low	LDV Personal	244	550	968	1,616	2,491	3,625	5,080	6,810	8,824	11,090	13,593	16,331	19,265	22,384	25,691	29,102
		LDV Commercial	24	69	141	242	410	650	979	1,406	1,980	2,705	3,591	4,660	5,863	7,193	8,638	10,131
		MDV	0	2	5	18	48	109	217	380	609	915	1,306	1,794	2,385	3,084	3,896	4,822
		HDV	-	-	0	0	1	3	9	20	36	58	87	128	181	245	319	404
		Bus	0	1	2	5	10	16	26	38	53	72	95	122	153	188	226	269
		Total	**269**	**622**	**1,116**	**1,882**	**2,959**	**4,403**	**6,310**	**8,654**	**11,502**	**14,840**	**18,672**	**23,036**	**27,847**	**33,093**	**38,771**	**44,729**
	High	LDV Personal	242	541	947	1,573	2,408	3,487	4,868	6,504	8,403	10,529	12,876	15,436	18,179	21,093	24,185	27,372
		LDV Commercial	22	63	125	213	354	557	833	1,192	1,676	2,282	3,022	3,902	4,911	6,040	7,300	8,620
		MDV	0	1	3	10	26	60	118	206	322	471	651	862	1,097	1,340	1,654	1,956
		HDV	-	-	-	-	0	1	2	5	10	18	29	45	68	98	134	178
		Bus	0	1	2	5	9	15	24	35	49	66	87	111	139	171	205	244
		Total	**265**	**607**	**1,077**	**1,801**	**2,797**	**4,119**	**5,845**	**7,942**	**10,461**	**13,365**	**16,665**	**20,357**	**24,394**	**28,742**	**33,479**	**38,369**
Vehicle Availability	Low	LDV Personal	243	468	744	1,170	1,714	2,540	3,603	4,858	6,290	7,948	9,866	12,179	14,779	17,595	20,684	23,928
		LDV Commercial	15	37	65	119	193	299	466	691	982	1,423	2,016	2,785	3,703	4,746	6,018	7,423
		MDV	0	1	4	9	20	40	70	141	253	410	644	953	1,337	1,786	2,332	2,947
		HDV	-	-	-	0	0	1	3	6	11	17	26	36	50	66	85	106
		Bus	0	1	2	5	8	14	23	34	48	66	88	113	142	175	212	252
		Total	**258**	**507**	**815**	**1,302**	**1,935**	**2,895**	**4,165**	**5,730**	**7,585**	**9,865**	**12,639**	**16,066**	**20,010**	**24,368**	**29,331**	**34,657**
	High	LDV Personal	346	833	1,498	2,406	3,536	4,876	6,441	8,224	10,233	12,457	14,894	17,541	20,383	23,399	26,597	29,895
		LDV Commercial	34	94	178	307	488	732	1,066	1,499	2,055	2,736	3,549	4,514	5,623	6,860	8,242	9,706
		MDV	1	3	9	23	53	112	200	325	492	707	977	1,309	1,706	2,164	2,714	3,332
		HDV	-	-	-	0	0	3	7	16	28	46	71	103	142	190	245	310
		Bus	0	1	3	6	11	17	26	38	52	70	92	117	147	180	217	257
		Total	**382**	**932**	**1,688**	**2,742**	**4,088**	**5,740**	**7,741**	**10,101**	**12,861**	**16,017**	**19,582**	**23,585**	**28,001**	**32,793**	**38,015**	**43,499**
Fuel Prices	Low	LDV Personal	235	520	909	1,511	2,319	3,363	4,701	6,287	8,131	10,202	12,487	14,979	17,657	20,522	23,582	26,762
		LDV Commercial	14	44	93	167	294	482	747	1,096	1,583	2,207	2,971	3,897	4,971	6,176	7,532	8,976
		MDV	0	0	1	3	11	33	75	143	239	366	528	728	966	1,229	1,584	1,970
		HDV	-	-	-	-	-	0	0	0	2	5	10	21	38	62	92	132
		Bus	0	1	2	4	9	15	23	34	48	65	86	110	138	170	206	245
		Total	**249**	**565**	**1,004**	**1,686**	**2,633**	**3,893**	**5,545**	**7,560**	**10,002**	**12,844**	**16,082**	**19,736**	**23,771**	**28,159**	**32,996**	**38,085**
	High	LDV Personal	251	569	1,001	1,673	2,573	3,733	5,222	6,989	9,044	11,355	13,907	16,693	19,689	22,853	26,185	29,600
		LDV Commercial	28	79	155	262	433	670	990	1,399	1,947	2,633	3,459	4,439	5,564	6,819	8,216	9,692
		MDV	1	3	7	22	54	115	218	369	575	843	1,179	1,590	2,079	2,644	3,301	4,039
		HDV	-	0	0	0	1	4	10	21	37	57	84	122	170	228	295	371
		Bus	0	1	2	5	10	17	26	38	53	71	93	120	150	183	221	262
		Total	**280**	**651**	**1,167**	**1,963**	**3,071**	**4,538**	**6,466**	**8,816**	**11,656**	**14,960**	**18,723**	**22,963**	**27,651**	**32,727**	**38,219**	**43,964**

			2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Electricity Rates	Low	LDV Personal	245	550	966	1,613	2,480	3,598	5,035	6,739	8,720	10,948	13,408	16,093	18,982	22,044	25,285	28,621
		LDV Commercial	24	68	137	235	393	616	922	1,315	1,846	2,515	3,323	4,288	5,399	6,640	8,025	9,492
		MDV	0	2	5	16	41	92	178	308	487	720	1,014	1,375	1,807	2,306	2,898	3,563
		HDV	-	-	-	0	0	2	7	15	27	44	66	98	140	191	251	320
		Bus	0	1	2	5	9	16	25	36	51	69	91	116	146	179	216	256
		Total	**269**	**621**	**1,110**	**1,868**	**2,924**	**4,325**	**6,167**	**8,413**	**11,131**	**14,295**	**17,902**	**21,971**	**26,474**	**31,360**	**36,676**	**42,254**
	High	LDV Personal	240	536	938	1,562	2,399	3,480	4,867	6,512	8,424	10,574	12,948	15,538	18,323	21,288	24,440	27,700
		LDV Commercial	21	60	121	210	356	566	857	1,234	1,749	2,400	3,192	4,142	5,239	6,466	7,841	9,300
		MDV	0	1	3	10	27	65	134	238	384	575	818	1,119	1,479	1,894	2,403	2,972
		HDV	-	-	-	-	0	1	3	7	15	26	42	66	99	140	190	249
		Bus	0	1	2	5	9	16	24	36	50	68	90	115	144	177	214	254
		Total	**262**	**597**	**1,064**	**1,786**	**2,791**	**4,128**	**5,884**	**8,027**	**10,622**	**13,644**	**17,090**	**20,980**	**25,284**	**29,966**	**35,088**	**40,475**
Vehicle Sales	Low	LDV Personal	240	529	916	1,503	2,275	3,256	4,487	5,919	7,552	9,351	11,298	13,382	15,580	17,869	20,249	22,655
		LDV Commercial	23	63	125	212	350	543	803	1,132	1,571	2,113	2,757	3,512	4,366	5,302	6,328	7,415
		MDV	0	1	4	12	31	70	138	238	373	547	762	1,023	1,329	1,676	2,085	2,534
		HDV	-	-	-	0	0	1	4	9	18	29	45	67	96	131	172	218
		Bus	0	1	2	5	9	14	22	32	44	59	76	96	119	144	171	200
		Total	263	595	1,047	1,731	2,665	3,885	5,455	7,331	9,557	12,098	14,938	18,081	21,489	25,121	29,004	33,024
	High	LDV Personal	246	559	994	1,681	2,620	3,853	5,467	7,421	9,738	12,393	15,383	18,708	22,355	26,305	30,576	35,075
		LDV Commercial	23	68	137	239	407	651	993	1,444	2,068	2,870	3,862	5,071	6,492	8,113	9,960	11,999
		MDV	0	1	4	14	37	87	175	312	504	762	1,094	1,511	2,021	2,621	3,358	4,200
		HDV	-	-	-	0	0	2	5	13	24	42	65	101	149	210	283	371
		Bus	0	1	2	5	10	17	27	41	58	80	107	139	177	220	269	324
		Total	270	629	1,137	1,938	3,074	4,609	6,669	9,231	12,393	16,147	20,510	25,530	31,194	37,469	44,447	51,968

Table F- 45: Annual EV Energy Consumption (GWh) by Sensitivity Scenario

			2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Baseline		LDV Personal	0.69	1.51	2.71	4.68	7.43	10.81	14.98	19.88	25.53	31.82	38.70	46.17	54.14	62.58	71.48	80.60
		LDV Commercial	0.07	0.22	0.46	0.82	1.44	2.37	3.70	5.46	7.92	11.08	14.93	19.56	24.90	30.88	37.55	44.61
		MDV	0.01	0.03	0.09	0.28	0.76	1.76	3.50	6.13	9.76	14.54	20.57	28.01	36.93	47.21	59.59	73.48
		HDV	-	-	-	0.00	0.02	0.22	0.76	1.78	3.37	5.67	8.78	13.37	19.43	26.95	35.91	46.32
		Bus	0.02	0.07	0.18	0.40	0.75	1.28	1.99	2.92	4.10	5.56	7.31	9.37	11.74	14.42	17.39	20.65
		Total	**0.79**	**1.83**	**3.44**	**6.19**	**10.41**	**16.43**	**24.92**	**36.18**	**50.70**	**68.66**	**90.29**	**116.47**	**147.13**	**182.04**	**221.93**	**265.67**
Battery Costs	Low	LDV Personal	0.70	1.55	2.80	4.89	7.81	11.40	15.79	20.93	26.85	33.45	40.67	48.51	56.85	65.68	74.99	84.52
		LDV Commercial	0.08	0.24	0.52	0.94	1.66	2.73	4.26	6.31	9.14	12.76	17.22	22.51	28.43	34.94	41.98	49.21
		MDV	0.01	0.04	0.12	0.40	1.08	2.45	4.88	8.56	13.70	20.58	29.39	40.37	53.67	69.38	87.66	108.50
		HDV	-	-	0.00	0.01	0.14	0.52	1.51	3.25	5.86	9.47	14.16	20.86	29.44	39.83	51.92	65.64
		Bus	0.02	0.08	0.19	0.42	0.79	1.33	2.08	3.06	4.30	5.84	7.69	9.86	12.37	15.19	18.34	21.78
		Total	**0.80**	**1.90**	**3.63**	**6.65**	**11.48**	**18.43**	**28.52**	**42.12**	**59.86**	**82.10**	**109.13**	**142.11**	**180.76**	**225.03**	**274.89**	**329.65**
	High	LDV Personal	0.68	1.49	2.65	4.54	7.16	10.39	14.37	19.03	24.43	30.44	37.04	44.20	51.83	59.89	68.41	77.13
		LDV Commercial	0.07	0.20	0.42	0.74	1.29	2.11	3.27	4.83	7.00	9.76	13.17	17.26	21.96	27.24	33.12	39.28
		MDV	0.01	0.03	0.07	0.22	0.58	1.34	2.66	4.63	7.26	10.59	14.65	19.40	24.68	30.15	37.23	44.02
		HDV	-	-	-	-	0.00	0.08	0.33	0.83	1.65	2.90	4.66	7.38	11.12	15.91	21.78	28.86
		Bus	0.02	0.07	0.18	0.39	0.73	1.24	1.93	2.82	3.96	5.36	7.03	9.00	11.26	13.81	16.64	19.74
		Total	**0.78**	**1.79**	**3.32**	**5.90**	**9.76**	**15.16**	**22.56**	**32.15**	**44.29**	**59.04**	**76.56**	**97.24**	**120.85**	**147.01**	**177.18**	**209.02**
Vehicle Availability	Low	LDV Personal	0.69	1.37	2.23	3.44	5.09	7.50	10.67	14.38	18.58	23.35	28.74	35.16	42.45	50.35	59.02	68.08
		LDV Commercial	0.05	0.13	0.23	0.41	0.69	1.09	1.75	2.71	4.01	5.95	8.52	12.02	16.31	21.26	27.35	34.10
		MDV	0.01	0.03	0.09	0.21	0.45	0.91	1.58	3.17	5.70	9.23	14.48	21.44	30.08	40.20	52.48	66.31
		HDV	-	-	-	0.00	0.02	0.22	0.55	1.06	1.79	2.82	4.18	5.93	8.10	10.71	13.77	17.30
		Bus	0.02	0.07	0.18	0.37	0.66	1.14	1.83	2.74	3.91	5.36	7.11	9.16	11.53	14.21	17.18	20.44
		Total	**0.76**	**1.60**	**2.73**	**4.44**	**6.91**	**10.86**	**16.38**	**24.06**	**33.99**	**46.71**	**63.03**	**83.71**	**108.46**	**136.72**	**169.81**	**206.24**
	High	LDV Personal	0.94	2.34	4.29	7.04	10.46	14.39	18.93	24.08	29.83	36.14	43.01	50.44	58.37	66.76	75.61	84.69
		LDV Commercial	0.11	0.32	0.62	1.12	1.87	2.92	4.42	6.43	9.05	12.31	16.23	20.89	26.25	32.24	38.93	45.99
		MDV	0.02	0.07	0.20	0.52	1.19	2.52	4.50	7.31	11.06	15.91	21.99	29.46	38.39	48.68	61.07	74.97
		HDV	-	-	-	0.00	0.05	0.47	1.20	2.53	4.59	7.54	11.52	16.66	23.07	30.80	39.88	50.37
		Bus	0.03	0.10	0.24	0.49	0.86	1.40	2.12	3.06	4.25	5.70	7.46	9.52	11.89	14.57	17.54	20.80
		Total	**1.10**	**2.83**	**5.36**	**9.17**	**14.42**	**21.70**	**31.19**	**43.42**	**58.78**	**77.60**	**100.20**	**126.97**	**157.97**	**193.06**	**233.04**	**276.81**
Fuel Prices	Low	LDV Personal	0.65	1.41	2.52	4.34	6.88	10.07	13.97	18.57	23.90	29.86	36.42	43.56	51.20	59.34	67.97	76.86
		LDV Commercial	0.04	0.13	0.29	0.56	1.04	1.80	2.94	4.51	6.76	9.70	13.35	17.79	22.96	28.78	35.33	42.29
		MDV	0.00	0.00	0.01	0.07	0.25	0.74	1.68	3.21	5.37	8.24	11.88	16.38	21.74	27.65	35.65	44.34
		HDV	-	-	-	-	-	0.00	0.01	0.06	0.27	0.76	1.69	3.43	6.16	9.99	15.00	21.47
		Bus	0.02	0.06	0.16	0.36	0.69	1.19	1.86	2.75	3.88	5.27	6.95	8.93	11.22	13.80	16.68	19.83
		Total	**0.71**	**1.61**	**2.98**	**5.33**	**8.86**	**13.80**	**20.46**	**29.11**	**40.17**	**53.83**	**70.29**	**90.10**	**113.27**	**139.57**	**170.62**	**204.79**
	High	LDV Personal	0.73	1.61	2.91	5.03	7.96	11.48	15.82	20.90	26.75	33.27	40.41	48.17	56.46	65.19	74.35	83.70
		LDV Commercial	0.09	0.28	0.57	1.01	1.72	2.75	4.19	6.09	8.68	11.98	15.97	20.73	26.18	32.26	39.03	46.15
		MDV	0.02	0.06	0.16	0.49	1.22	2.59	4.90	8.31	12.95	18.97	26.53	35.77	46.77	59.48	74.28	90.87
		HDV	-	0.00	0.00	0.05	0.24	0.66	1.70	3.43	5.93	9.32	13.67	19.81	27.62	37.03	47.95	60.34
		Bus	0.02	0.08	0.20	0.43	0.80	1.34	2.08	3.05	4.27	5.77	7.57	9.69	12.12	14.86	17.91	21.23
		Total	**0.85**	**2.03**	**3.85**	**7.01**	**11.93**	**18.82**	**28.69**	**41.77**	**58.58**	**79.31**	**104.15**	**134.15**	**169.15**	**208.82**	**253.51**	**302.28**

			2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Electricity Rates	Low	LDV Personal	0.70	1.54	2.76	4.78	7.59	11.04	15.28	20.25	25.96	32.32	39.28	46.84	54.92	63.45	72.43	81.63
		LDV Commercial	0.07	0.23	0.49	0.87	1.52	2.48	3.84	5.65	8.15	11.35	15.25	19.92	25.29	31.30	38.00	45.08
		MDV	0.01	0.04	0.11	0.36	0.93	2.06	4.01	6.94	10.95	16.20	22.81	30.94	40.66	51.89	65.21	80.17
		HDV	-	-	-	0.00	0.08	0.37	1.11	2.42	4.39	7.14	10.76	15.99	22.77	31.06	40.83	52.06
		Bus	0.02	0.07	0.19	0.41	0.76	1.29	2.01	2.95	4.13	5.60	7.36	9.43	11.81	14.50	17.49	20.76
		Total	**0.80**	**1.88**	**3.54**	**6.42**	**10.88**	**17.24**	**26.26**	**38.20**	**53.59**	**72.61**	**95.46**	**123.12**	**155.45**	**192.20**	**233.97**	**279.70**
	High	LDV Personal	0.68	1.48	2.64	4.56	7.23	10.55	14.63	19.44	24.99	31.20	38.00	45.37	53.24	61.57	70.39	79.43
		LDV Commercial	0.06	0.19	0.41	0.75	1.34	2.22	3.50	5.22	7.63	10.74	14.54	19.12	24.42	30.36	37.00	44.04
		MDV	0.01	0.02	0.06	0.22	0.61	1.47	3.01	5.37	8.63	12.95	18.41	25.17	33.29	42.63	54.06	66.86
		HDV	-	-	-	-	0.00	0.11	0.46	1.18	2.39	4.23	6.81	10.73	16.05	22.77	30.88	40.45
		Bus	0.02	0.07	0.18	0.39	0.74	1.26	1.97	2.90	4.07	5.52	7.26	9.31	11.67	14.34	17.31	20.55
		Total	**0.76**	**1.76**	**3.29**	**5.92**	**9.92**	**15.61**	**23.57**	**34.11**	**47.73**	**64.63**	**85.02**	**109.70**	**138.66**	**171.67**	**209.64**	**251.34**
Vehicle Sales	Low	LDV Personal	0.68	1.47	2.60	4.42	6.91	9.99	13.67	17.90	22.68	27.90	33.51	39.47	45.72	52.20	58.92	65.67
		LDV Commercial	0.07	0.21	0.44	0.77	1.34	2.16	3.31	4.82	6.88	9.47	12.57	16.22	20.34	24.88	29.84	35.08
		MDV	0.01	0.03	0.08	0.27	0.70	1.58	3.09	5.34	8.38	12.30	17.15	23.02	29.91	37.70	46.91	57.02
		HDV	-	-	-	0.00	0.02	0.19	0.67	1.54	2.87	4.75	7.26	10.87	15.56	21.26	27.91	35.50
		Bus	0.02	0.07	0.18	0.37	0.69	1.16	1.78	2.58	3.56	4.76	6.17	7.79	9.62	11.65	13.86	16.24
		Total	**0.77**	**1.78**	**3.29**	**5.83**	**9.66**	**15.09**	**22.52**	**32.18**	**44.38**	**59.18**	**76.65**	**97.37**	**121.15**	**147.70**	**177.44**	**209.51**
	High	LDV Personal	0.70	1.55	2.82	4.95	7.98	11.70	16.43	22.10	28.75	36.30	44.73	54.03	64.16	75.08	86.81	99.18
		LDV Commercial	0.07	0.22	0.48	0.87	1.56	2.60	4.12	6.18	9.11	12.94	17.72	23.56	30.43	38.28	47.21	57.04
		MDV	0.01	0.03	0.09	0.30	0.83	1.95	3.94	7.02	11.35	17.14	24.61	34.00	45.48	58.98	75.55	94.50
		HDV	-	-	-	0.00	0.03	0.24	0.87	2.05	3.95	6.74	10.60	16.39	24.19	34.06	46.04	60.25
		Bus	0.02	0.08	0.19	0.43	0.81	1.40	2.22	3.31	4.72	6.48	8.65	11.25	14.30	17.82	21.80	26.24
		Total	**0.80**	**1.89**	**3.59**	**6.56**	**11.21**	**17.90**	**27.57**	**40.66**	**57.88**	**79.61**	**106.30**	**139.23**	**178.56**	**224.21**	**277.41**	**337.21**

Table F- 46: EV Charging Hourly Load Profile (MW) in 2034 under Unmanaged Charging by Scenario

		0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Baseline		106	88	63	39	21	11	9	10	14	20	29	39	46	50	51	53	58	71	87	102	111	114	115	113
DCFC	Low	160	133	95	59	33	18	15	17	24	32	44	58	67	74	77	79	89	108	135	160	175	177	179	174
	High	242	202	144	90	50	28	24	26	38	50	68	87	100	110	114	119	134	165	207	248	272	274	276	266
Incentives	Low	134	111	80	49	27	15	12	13	19	27	37	49	57	63	64	67	74	90	112	133	145	147	148	145
	High	221	184	132	82	46	25	21	24	34	45	62	80	92	101	105	109	122	151	188	225	246	249	251	242
Level 2	Low	113	94	68	41	22	12	10	11	15	22	31	42	49	54	55	57	63	76	93	109	119	121	123	120
	High	116	96	69	42	23	12	10	11	16	22	32	43	50	55	56	58	64	77	95	112	121	124	126	123
$5M Investment		209	149	93	52	29	24	27	38	51	70	91	104	115	119	124	139	171	213	255	279	282	284	275	251
$20M Investment		267	222	158	99	55	31	26	29	41	55	74	96	110	121	126	131	147	182	228	273	299	302	303	293

Table F- 47: EV Peak Load Impact (MW) in 2034 under Unmanaged Charging by Scenario

		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Baseline		0.39	0.93	1.68	2.90	4.68	7.30	10.94	15.66	21.66	29.10	37.90	48.38	60.52	74.16	89.51	106.08
DCFC	Low	0.39	0.96	1.80	3.19	5.31	8.43	12.93	18.85	26.77	36.85	49.62	66.62	87.80	111.30	137.46	165.45
	High	0.39	1.04	2.12	4.05	7.18	11.99	19.16	28.92	42.88	61.62	85.41	112.90	143.90	178.11	215.63	255.40
Incentives	Low	0.48	1.14	2.05	3.45	5.49	8.33	12.23	17.25	23.58	31.14	40.25	51.24	64.10	78.71	95.29	113.33
	High	0.52	1.29	2.37	3.99	6.37	9.61	14.08	19.42	26.06	33.62	42.72	53.72	66.59	81.22	97.82	115.86
Level 2	Low	0.39	0.95	1.75	3.06	5.01	7.90	12.08	17.63	24.88	33.94	45.10	58.78	75.39	93.95	114.75	137.16
	High	0.40	0.99	1.92	3.49	5.96	9.85	15.79	24.03	35.24	49.69	68.34	91.98	122.38	155.89	192.83	232.06
Proposed $5M Investment		0.39	1.04	2.11	4.11	7.41	12.63	20.47	31.03	44.64	63.57	87.30	114.35	144.74	178.16	214.95	253.88
Proposed $20M Investment		0.39	1.07	2.23	4.42	8.09	13.86	22.65	34.49	51.17	72.48	97.49	126.69	159.93	196.90	237.79	280.98

Table F- 48: Cost Effectiveness of Modeled Scenarios Under Unmanaged and Managed Charging Load by 2034

		Unmanaged EV Load				EV Load Management			
		Benefits	Costs	BCR	NPV	Benefits	Costs	BCR	NPV
Baseline		$119,480,561	$(163,207,702)	**0.73**	**$(43,727,141)**	$119,480,561	$ (51,535,943)	**2.32**	**$ 67,944,618**
DCFC	**Low**	$51,428,913	$(71,873,727)	**0.72**	**$(20,444,813)**	$ 51,428,913	$(25,052,041)	**2.05**	**$ 26,376,872**
	High	$162,812,613	$(221,649,090)	**0.73**	**$(58,836,477)**	$ 162,812,613	$ (80,486,027)	**2.02**	**$ 82,326,586**
Level 2	**Low**	$25,468,957	$(40,093,007)	**0.64**	**$(14,624,050)**	$ 25,468,957	$ (14,470,629)	**1.76**	**$ 10,998,328**
	High	$102,085,295	$(164,390,738)	**0.62**	**$(62,305,443)**	$ 102,085,295	$(58,551,075)	**1.74**	**$ 43,534,220**
Incentives	**Low**	$10,634,373	$(16,158,335)	**0.66**	**$(5,523,962)**	$ 10,634,373	$(8,029,117)	**1.32**	**$ 2,605,256**
	High	$16,937,965	$(36,481,899)	**0.46**	**$(19,543,933)**	$16,937,965	$ (21,922,482)	**0.77**	**$ (4,984,516)**
		$157,093,300.56	$(214,506,952.87)	**0.73**	**$(57,413,652.30)**	$157,093,301	$(70,738,954.38)	**2.22**	**$86,354,346.18**
$20M Investment		$197,333,549	$(267,591,522)	**0.74**	**$ (70,257,973)**	$197,333,549	$(95,635,637.66)	**2.06**	**$ 101,697,911.59**

Schedule D
Electric Vehicle Overview

Electric Vehicle Overview

Introduction

Customers consider many factors when purchasing a vehicle including price, operating costs and lifestyle. Since 2010, electric vehicles ("EVs") have become an increasingly competitive option in the vehicle marketplace.

EV growth is commonly driven by: (i) investments in charging infrastructure, (ii) financial incentives, and, (iii) public education and awareness initiatives.

The Muskrat Falls project will connect the province to the North American electricity grid. As a result, surplus electricity will be available in Newfoundland and Labrador to fuel an EV market. The net revenue gained from domestic sales could be used to provide rate mitigating benefits to customers.

Electric Vehicles Technologies

An EV is an alternative fuel vehicle that uses an electric motor for propulsion instead of more common propulsion systems based on gas powered internal combustion engines. EVs contain batteries that store electricity which powers the vehicle's wheels via an electric motor. An EV that travels 20,000 km/year would use approximately the same amount of electricity every year as a typical electric water heater. This equates to a cost of approximately $0.03/km for an EV compared to a cost of approximately $0.12/km for a conventional vehicle. [1]

There are two major types of EVs:

Battery Electric Vehicle

("BEV") – this type of vehicle has an engine and is propelled by electricity that comes from one or several high capacity batteries. BEVs are powered by electricity by plugging in to an electrical outlet or specialty Electric Vehicle Charging Equipment ("EVCE").

Plug-in Hybrid Electric Vehicle

("PHEV") – this type of vehicle combines a gasoline or diesel engine with an electric motor and a rechargeable battery. Modern PHEVs can be driven in electric mode over varying distances before the combustion engine is required. Unlike earlier hybrids that use gasoline as their main power source, PHEVs can be plugged-in and recharged from an outlet, allowing them to drive extended distances using only electricity.

Refuel or Recharge

Vehicle Type	Gasoline	Electricity
Gas Only	X	
PHEV	X	X
BEV		X

1 This is based on the efficiency of an internal combustion engine vehicle of 0.1 L/km, and the price of self-serve gasoline of $1.163 per/L on the Avalon Peninsula, as approved by the Board on December 10, 2020. Electric vehicle costs are based on the efficiency of a battery electric vehicle of 0.18 kWh/km and a residential customer price of electricity of $0.12203/kWh plus HST ($0.14/kWh).

The primary difference between a BEV and a PHEV is the driving range. A BEV's driving range is limited by the storage capacity of its battery and availability of charging infrastructure. A PHEV is equipped with a fuel tank and an internal combustion engine which allows for an increased driving range.[2]

EV efficiency is measured in kWh/km. EVs convert about 59%–62% of the electrical energy to power that allows the vehicle to operate. Conventional gasoline vehicles only convert about 16%–25% of the energy in gasoline to power the wheels.[3]

The battery system in an EV is the key technology as it defines its range and performance characteristics. EV batteries are designed to last approximately 12 to 15 years in moderate climates and 8 to 12 years in severe climates.[4] Battery prices fell 87% from 2010 to 2019, with the introduction of new chemistries, new manufacturing techniques and simplified design.[5]

Electric Vehicle Charging Equipment

Charging stations can be found in a variety of places, including shopping malls, restaurants, office buildings, etc. The development and proliferation of EVs must be accompanied by EV charging infrastructure.

Figure 1 shows the types of EV charging infrastructure.

	Level 1	Level 2	Level 3
Connection:	• Standard 120 volt household outlet	• 240 volt plug	• 480 volt plug
Installation:	• Does not require the installation of charging equipment	• Requires installation of charging equipment by a qualified electrician	• Requires specialized, high-powered charging equipment installation by a qualified electrician
Rate of Charge:	• Up to 8 km of range per hour of charging	• Up to 30 km of range per hour of charging	• Up to 140 km of range per hour of charging

Primarily, there are 3 types of chargers. Level 1 chargers use a regular socket that you would find in a home. This type of charging takes the longest, anywhere from 9-50 hours.

---

2 See Environmental Protection Agency, *Explaining electric & plug-in hybrids electric vehicles.*
3 See Environmental Protection Agency, *Where the Energy Goes: Gasoline Vehicles.*
4 See U.S. Department of Energy, *Electric vehicle benefits and considerations.*
5 Bloomberg New Energy Finance, *Global EV outlook*, 2020.

Second, there are level 2 chargers. These type of chargers are often installed at home or at workplaces. It can take 2 to 9 hours to fully charge.

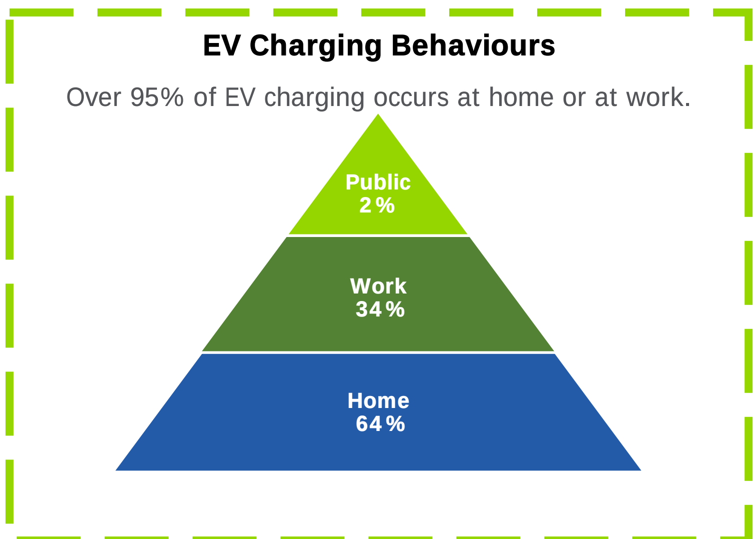
Lastly, there are Level 3 chargers, also referred to as Direct Current Fast Chargers ("DCFC"). These chargers provide the fastest rate of charge reaching 80% of a vehicle range in 30 minutes. This is the type of charging that is required to ease customers concerns about their ability to reach their destinations. These are typically installed along the highway for long distance travel or in high population areas.

Barriers to EV Adoption

In order to advance EV adoption, a number of barriers must be removed.

EV market barriers are the access to charging infrastructure, the upfront capital cost, and public perceptions about EVs. A lack of charging infrastructure creates the consumer perception that EVs will run out of battery power and be left 'stranded' or unable to reach their destination.

Overall, 89% of respondents said that the range of their EV is sufficient for their daily needs.[6] Further, even though access to public charging is improving, 86% of respondents said they primarily charge at home.



EVs typically have a higher up front purchase cost than conventional vehicles but lower ongoing operating costs. The average incremental capital cost difference between a conventional family sedan and a similar model EV is approximately $19,000.[7] The main cost driver for EVs is the large battery that represents approximately 75% of the vehicle's power train cost.[8]

Fuel costs, on the other hand, are up to 80% lower for an EV compared to a conventional vehicle.[9]

---

6 Fleetcarma, *2020 EV driver insights survey*, November 2020.

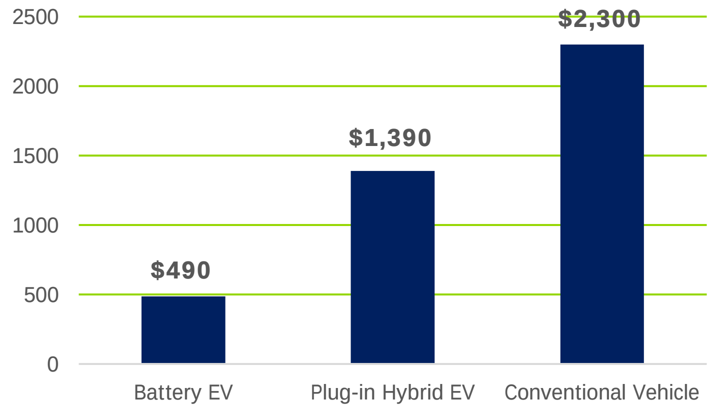
7 The purchase price of eight EVs were compared to similar internal combustion engine vehicles. The average difference in price between EVs and the internal combustion engine vehicles was $18,820.

8 Power train typically consists of the main components of a vehicle that generate power. This typically includes the engine, transmission, drive shafts, etc.

9 Based on electricity rates of $0.135/kWh.

Annual Fuel Cost of an

EV vs. Conventional Vehicle



Range anxiety continues to be a barrier to adoption, though in most cases, the distance that EV drivers travel each day is well within the range capacity of an EV. For example, the average passenger vehicle in Newfoundland and Labrador travels approximately 50 km each day.[10] The range that EVs can travel in a single charge has been increasing in recent years. The average range has grown from 219 km in 2013, to 386 km in 2019.[11] Based on this range capacity, the 50 km traveled each day by drivers in Newfoundland and Labrador can be accommodated.

Consumer knowledge and public perceptions about EVs are another barrier to EV adoption. A consumer survey conducted by McKinsey & Company in 2019 shows that about 50% of all consumers today are not yet familiar with EVs and related technology.[12]

There are also difficulties with EV availability at dealerships and limited local service and maintenance options.

EV Markets

Global EV stock is expanding rapidly. At the end of 2019, there were more than 7 million vehicles worldwide.[13] Over 2.1 million of these were sold in 2019, alone. EVs accounted for 2.6% of global car sales and about 1% of global car stock in 2019, which represents a 40% year-on-year increase.[14]

The COVID-19 pandemic will affect global EV markets, although to a lesser extent than it will the overall passenger car market. Based on car sales data during January to April 2020, current estimates provide that the

---

[10] Natural Resources Canada, *2008 Canadian vehicle survey update report*, 2008.

[11] Canada Energy Regulator, *Market Snapshot: Average electric vehicle range almost doubled in the last six years*, June 2019.

[12] McKinsey & Company, *The road ahead for e-mobility,* 2019.

[13] See International Energy Agency, *Global EV outlook*, 2020.

[14] See International Energy Agency, *Global EV outlook*, 2020.

passenger car market will contract by 15% over the year relative to 2019, while electric sales for passenger and commercial light-duty vehicles will remain broadly at 2019 levels. Bloomberg estimates that EV sales will account for about 3% of global car sales in 2020. This outlook is underpinned by supporting policies, particularly in China and Europe. China recently extended its subsidy scheme until 2022. China and Europe also recently strengthened and extended their New Energy Vehicle mandate and CO_2 emissions standards.

The global EV stock remains concentrated in China, Europe and the United States, but is increasing across the globe. China and Europe achieved new records in EV market share at 4.9% and 3.5% respectively. By 2019, nine countries had more than 100,000 EVs on the road, and more than 20 countries reached market shares above 1%.[15] The greatest market penetration is in Norway, where in 2020, EV market share exceeded 75%.[16] Norway has a wide array of EV incentives and has a goal of 100% zero-emission vehicles by 2025.

While EV adoption has accelerated across Canada, EV sales vary significantly across the provinces. Uptake has been strongest in British Columbia and Quebec, the two provinces with purchase incentives as well as policy mandates requiring that EVs represent an increasing proportion of passenger vehicle sales. Since the introduction of federal incentives in 2019, EV market share has exceeded 10% in British Columbia and 7% in Quebec.[17] In the first and second quarters of 2020, 3.5% of new vehicle sales registered in Canada were EVs. This corresponds to over 21,000 new EV registrations. Of new EV registrations in this period, over 94% were in Quebec, Ontario and British Columbia.[18] However, EV sales continue to rise across the country. The share of EV sales occurring outside of British Columbia, Quebec and Ontario has risen from approximately 2.2% in 2017 to 4.5% in 2019.[19]

---

[15] See International Energy Agency, *Global EV outlook*, 2020.
[16] See Clean Technica, *Norway EV Market Share Breaks All Records*, April 2020.
[17] See Electric Mobility Canada, *Electric Vehicle Sales in Canada – Q3 2019*.
[18] Statistics Canada, *New Motor Vehicle Registrations, first half of 2020.*
[19] See Electric Mobility Canada, *Electric Vehicle Sales in Canada – Q3 2019*.

Schedule E
Potential Study Addendum: Demand Response Assessment

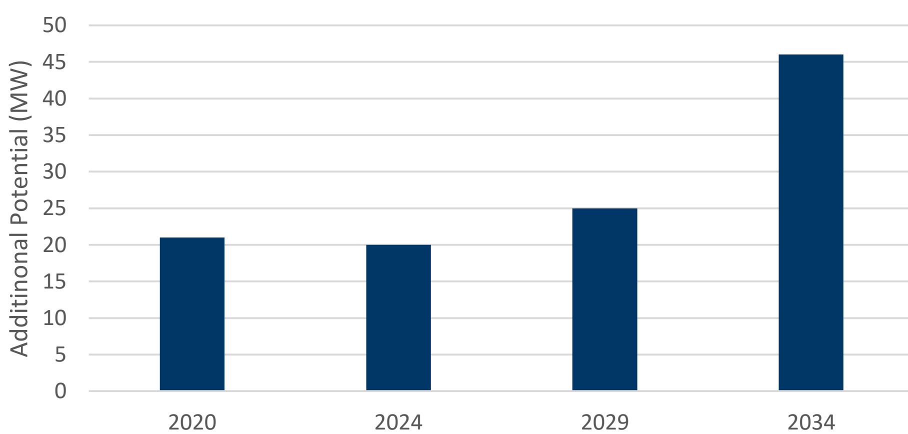
ADDENDUM: DEMAND RESPONSE POTENTIAL ASSESSMENT – FURTHER ANALYSIS

KEY FINDINGS

Based on the analysis presented above, and the comparison of the results among the scenarios presented in Figure 1, Figure 2 and Table 1 below, the following key observations are drawn:

1) **Consider updating the Corner Brook Curtailment contract to allow for longer duration events:** A simple change in the Corner Brook contract to allow a maximum 16-hour event duration in a single day would greatly improve the potential for ODR (46 MW) for dynamic rates programs on the IIC system, but only toward the end of the study period (after 2030, as per Figure 1 below). This is largely because the extended Corner Brook curtailment duration would allow for shifting residential loads to the early morning and late evening without creating a new peak at these times. Despite the observation that this would yield benefits later in the study, the contract adjustment should be made sooner if possible, as it would provide more flexibility to all current and possible DR strategies.

Figure 1: Additional Peak Load Reduction Potential resulting from expanding the Corner Brook Event duration to 16h as compared to the No TOU/CPP Scenario



2) **Using a combined residential customer CPP and commercial TOU rate design offers significant additional peak load reduction potential, however, this does not fully emerge until after 2030.** Optimizing dynamic rates approaches offers the highest peak load reduction (230 MW in 2034) when combined with a 16-hour curtailment constraint for Corner Brook. However, the ODR, TOU and CPP programs do not provide sufficient benefits to carry the full cost of the AMI investments needed to enable these programs before 2034. A full business case assessment for AMI may

reveal other benefits streams that could be combined with TOU/CPP programs to render the investment cost-effective.

3) **Take a stepwise approach to considering new DR programs:** Currently there is little additional benefit from new DR programs, including the TOU/CPP programs which do not appear to be cost-effective in the near term. In the initial years, focus should remain on expanding the current commercial and industrial curtailment programs (as per the initial report recommendations) along with expanding the duration of the Corner Brook curtailment event duration. However, as EVs become more prevalent in the province, they may eventually contribute to a new evening peak. As this trend takes hold, the Utilities should pilot EV load management strategies (i.e. dynamic rates for customers with EV chargers or direct EV load management). This will help determine which option is most effective at mitigating the impact of EV charging on the utility annual peak, and help ensure that investments in EV adoption return benefit to the system.

Figure 2: Net Achievable DR Impact by Program – Initial Potential Study (Scenario 1) and Updated Scenarios (2034)

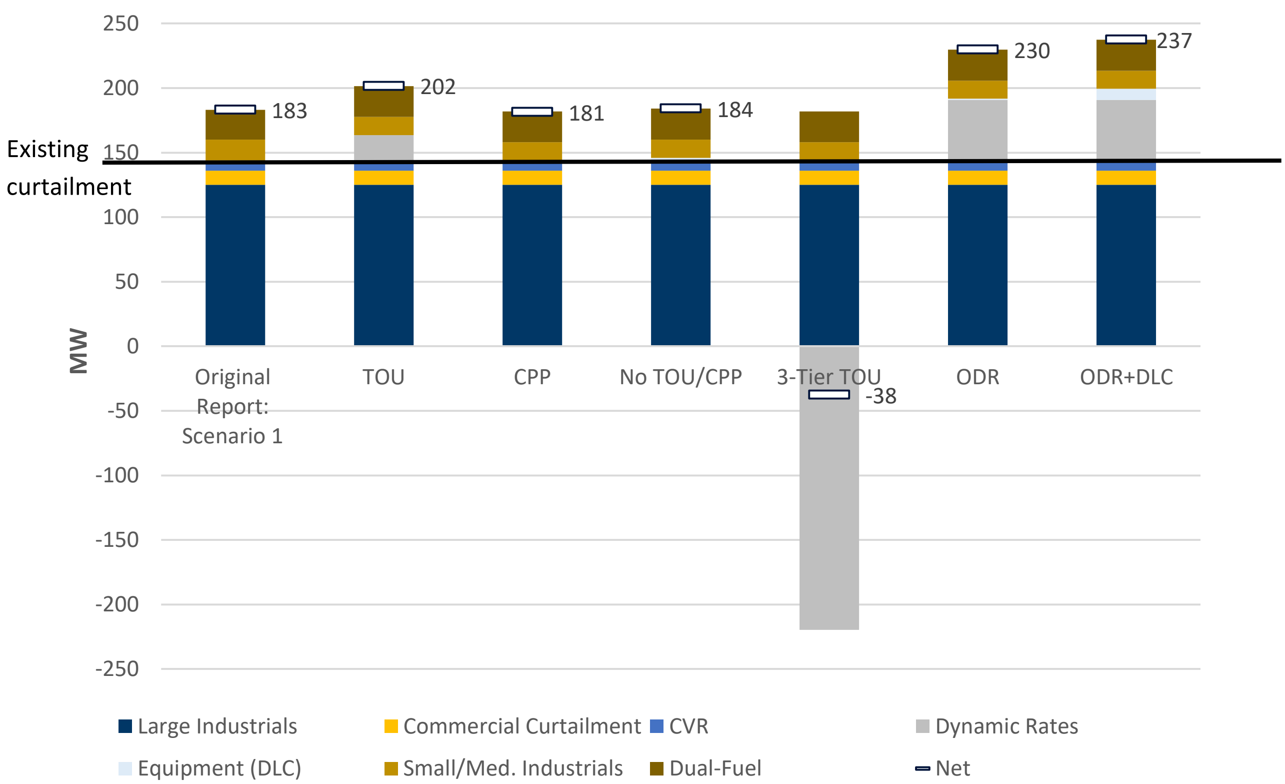


Table 1: Total Achievable DR Potential (MW) for all Scenarios with optimized Corner Brook contract

Scenario	2020	2024	2029	2034
Baseline (Report Scenario 1)	182	182	183	183
TOU Scenario	190	190	194	202

CPP Scenario	162	160	161	181
No TOU/CPP Scenario	179	180	182	185
3-Tier TOU Scenario	14	6	-13	-38
ODR Scenario	200	200	208	230
ODR with DLC Scenario	201	202	209	237

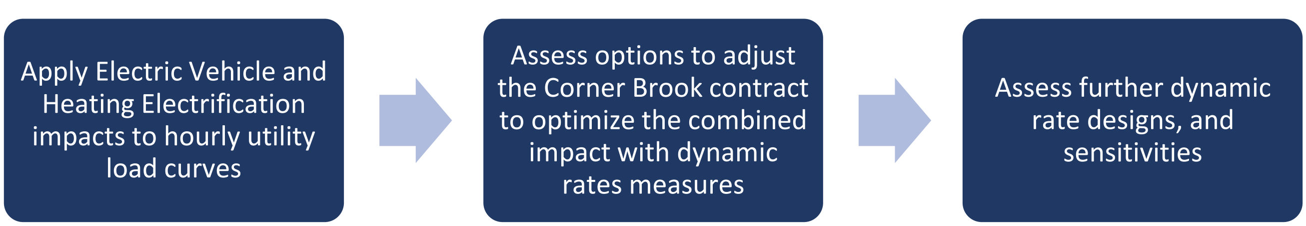
INTRODUCTION

In the recently completed *Newfoundland and Labrador Conservation Potential Study (2020-2034)*, Dunsky performed an assessment of demand response (DR) (Chapter 4), space and water heating fuel switching (Chapter 5), and electric vehicle adoption potentials (Chapter 6). In the demand response assessment, it was observed that the Corner Brook curtailment contract (the largest single DR resource available on the Island Interconnected system) contained conditions that significantly constrained the ability of other DR programs to generate net peak reductions. Most notably, the study found that Time of Use (TOU) and Critical Peak Pricing (CPP) rate designs would reduce the effectiveness of the Corner Brook curtailment by shifting peak loads to times that cannot be addressed under the constraints of the current Corner Brook contract, and thus they were not able to provide cost-effective net peak demand reductions under the current constraints. In the original study, the combined impact of EV adoption and electrification of heating loads (fuel switching via electric heat pumps) on the DR potential was not assessed.

Given that each of fuel switching, EV adoption, and DR programs all impact the shape and magnitude of the utility load curve, the NL Utilities requested that Dunsky revisit the DR analysis to account for three further factors.

1) Reassess the DR potential after the combined impact of energy efficiency, fuel switching, and EV adoption have been applied to the standard peak day load curve;
2) Apply adjusted Corner Brook curtailment contract conditions, designed such that it would be more compatible with other DR programs, in particular for dynamic rates programs, and;
3) Assess new dynamic rate scenarios and sensitivities to determine if there is an optimized rate design that could yield cost-effective peak demand reduction over the study period (2020-2034).

Figure 3: DR Potential Update Steps covered in this Addendum



Dunsky completed this further assessment of the DR potential, and the results are presented in this Addendum to the original report. All assessment was limited to the **Island Interconnected System (IIC),** starting with the same baseline load curve and growth projections as applied in the *Newfoundland and Labrador Conservation Potential Study (2020-2034).*

UPDATED SCENARIOS AND SENSITIVITIES

To assess the potential of an optimized Corner Brook curtailment contract, six scenarios were assessed. In each case these were tested against the updated load curve that included the baseline EV and heating electrification adoption projections as presented in the *Newfoundland and Labrador Conservation Potential Study (2020-2034).*

Table 2: New DR Scenarios Assessed (IIC)

Scenario	DR Programs
1	TOU rate design as per Potential Study **(TOU)**
2	CPP Program from Potential Study **(CPP)**
3	Only applies the new Corner Brook contract **(no TOU/CPP)**
4	3-tier TOU rate design from the Marginal Cost Study Updated **(3-Tier TOU)**
5	Optimized Dynamic Rate Design **(ODR)**
6	ODR with Direct Load Control (DLC) **(ODR + DLC)**

In addition to the scenario-specific DR programs listed above, the same set of Type 2 DR measures (measures with no same day rebound or pre-charge load curve impacts) were applied for each scenario as per those outlined in Chapter 4 of the *Newfoundland and Labrador Conservation Potential Study (2020-2034).*

Sensitivities: In addition to the six scenarios assessed as listed above, two further sensitivities were applied.

1. First the impact of extending the maximum total Corner Brook curtailment duration from 250 hours per year to 350 hours per year was assessed to determine the portion of the Maritime Link that could be committed to off-island sales.
2. Second, the most promising DR scenario was assessed with, and without the impact of natural adoption of heat pumps for customers with electric baseboard heat on the peak day load curve. This was included to account for uncertainty over the peak coincident load from heat pumps in the NL climate.

KEY ASSUMPTIONS

Table 3 below presents the key inputs and assumptions applied under the DR Potential update assessment and scenarios.

Table 3: Assumptions and Inputs Applied in the DR Potential Update

Name	Scenarios	Input & Assumptions
Corner Brook Curtailment Optimization	All	Our initial analysis shows that extending the maximum daily period of curtailment from 12 hours to 16 hours (for the full 105 MW) would prove sufficient to allow optimization of other DR programs. See Table 14 in the appendix for further details.
Fuel Switching Projections	All	The **Low Scenario** was applied for the projected heating fuel switching adoption, as described in Chapter 5 of the *Newfoundland and Labrador Conservation Potential Study (2020-2034).* This projection covers the expected natural adoption of ductless and central heat pumps, as well as heat pump water heaters, and the associated load impacts, as described therein. It is important to note that the Fuel Switching analysis included conversion from electric baseboard space heating to heat pumps, which is projected to be significantly larger than conversion from oil-fired or wood-fired heating to heat pumps.
Electric Vehicle Projections	All	The **Baseline Scenario** was applied for the projected EV adoption rates, as described on p. 112-114 in the *Newfoundland and Labrador Conservation Potential Study (2020-2034).* This covers the expected adoption of Light Personal Vehicles, Light Commercial Vehicles, Medium-Duty Vehicles, Heavy-Duty Vehicles, considering current market conditions and federal government incentives.
Dynamic Rates	1, 2, 4, 5, 6	All scenarios apply an opt-out assumption, with 85% participation in dynamic rates programs. 1. **Scenarios 1 & 2** apply the optimal two-tier TOU (2:1) and CPP (3:1) rate designs as described in p. 68-70 in the *Newfoundland and Labrador Conservation Potential Study (2020-2034).* 2. **Scenario 4** applies the three-tier TOU rate design from the recent NL Hydro marginal cost study.[1] 3. **Scenario 5** applies an optimal TOU/CPP combination that was designed to maximize the total DR potential when coupled with the 16-hour duration Corner Brook contract conditions (see Figure 9 presented later in this update for details).
EV Load Management [2]	1, 2, 3, 4, 5, 6	1. **Active** load management via remote utility control of the charger (95% peak hour load impact reduction). 2. **Passive** load management under the dynamic rates programs (75% peak hour load impact reduction).

[1] Source: "Marginal Cost Study Update – 2018," Nov. 15, 2018, NL Hydro.

[2] Active and passive load management impacts are based on Dunsky's overview of multiple pilots and projects assessing impact of EV load management (Charge the North, BC Hydro, Green Mountain Power, PG&E, NSPI, etc.).

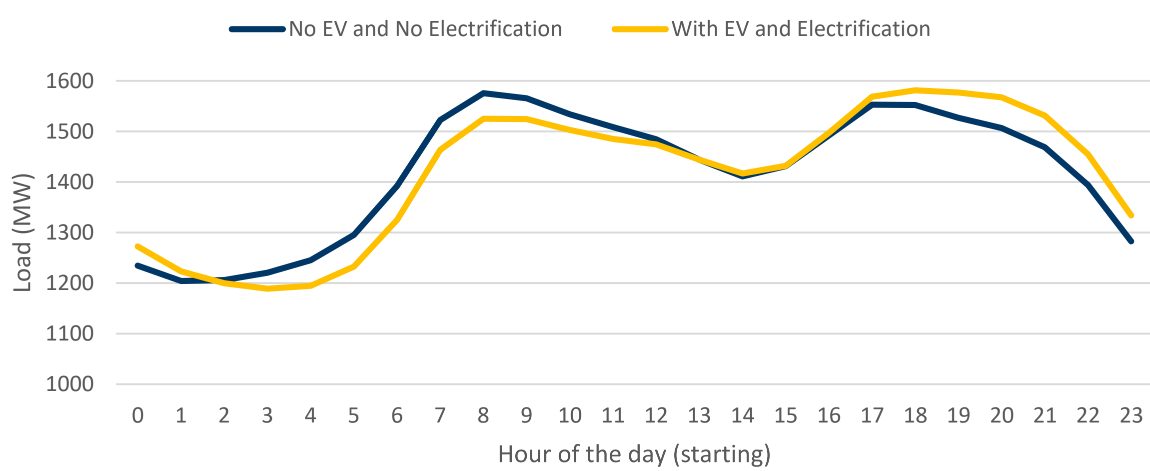
		Scenario 6: Combines active and passive EV load management. For all customers who opt out of the dynamic rates, they become eligible to participate in the Active EV load management measure.

RESULTS

IMPACT ON LOAD CURVE

The first step of the DR Potential Update entailed applying the projected heat pump and EV adoption, without any load management, to the utility peak load and to assess the impact on the shape of the standard peak day load curve. Figure 4 below illustrates the expected impact by 2034. While the adoption of EVs is expected to somewhat raise the annual peak load due to EV charging coincident with the evening peak, the adoption of heat pumps, particularly in conversions from electric resistance heating will help to somewhat reduce the peak load.[3] Overall, the combined effect slightly increases the daily peak by 2034, and shifts the daily maximum from a morning peak to an early evening peak. While the combined effect of EV adoption and heat pump adoption may change the shape of the load curve, and the timing of the daily peak, these changes are not sufficient to alter the overall economic conclusions related to investing to support EV adoption as described in the initial study.

Figure 4: Combined impact of EV and Electrification on the 2034 Standard Peak day load curve (2034)



SCENARIOS 1-3: OPTIMIZATION OF THE CORNER BROOK CONTRACT

Applying the updated peak day load curves, the DR Model was then used to assess the annual peak load reduction potential for each assessment. Figure 5 below presents the results for the full set of DR

[3] Further charts showing the individual impacts of EV adoption and Fuel Switching are provided in the appendix to this Addendum.

programs at the start year of each 5-year interval, as was assessed in the *Newfoundland and Labrador Conservation Potential Study (2020-2034).*

Figure 5: Achievable DR Potential for Scenarios 1-3 under with optimized Corner Brook contract[4]

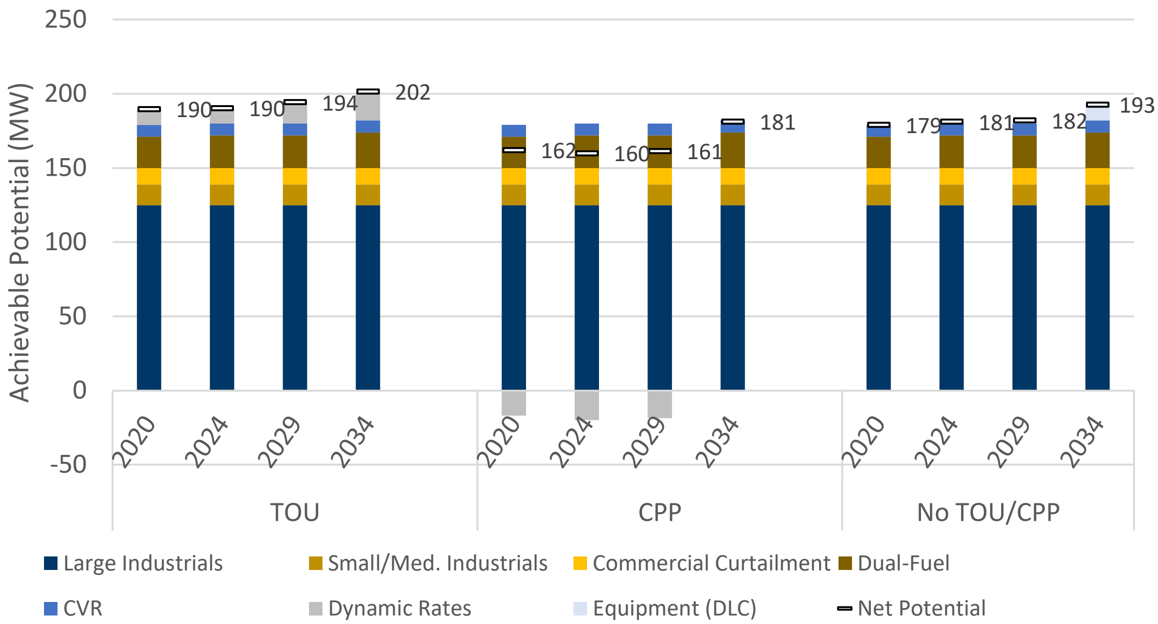
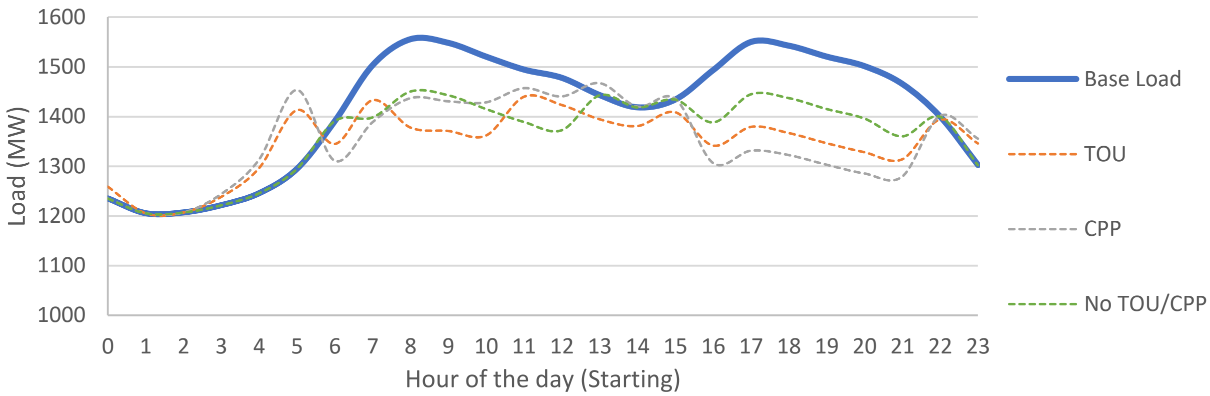


Figure 6 below provides further details on how each scenario-specific DR program interacts with the standard peak day load curve. In each case the impact of the scenario specific program was assessed against the standard peak day to determine the potential, and in conjunction with the 16-hour maximum daily duration Corner Brook contract constraints over 5-years of historical IIC load curves to ensure that no new peak days arise.

4 As shown in the *Newfoundland and Labrador Conservation Potential Study (2020-2034)* - Vol.2 table F-19, under the mid scenario, heat pumps are mainly applied to replace electric resistance heating. Since all other replacements combined (combustible fuel conversions to heat pump) account for less than 1% of total customers, it was assumed that the potential of the dual fuel program would not be impacted.

Figure 6: Standard Peak Day impacts Scenario 1-3 (2020)



Overall it can be seen that the 2:1 TOU scenario provides the highest potential of the initial options assessed using the dynamic rate programs as defined in the initial report. Further examination of Figure 6 indicates the CPP scenario suffers from a higher mid-day peak than the TOU scenario, as it more aggressively displaces peak load from the morning and evening heating peaks. On the other hand, the no TOU/CPP scenario is less successful than the TOU scenario at mitigating the morning and evening residential heating peaks.

SCENARIOS 4-6: OPTIMIZATION OF DYNAMIC RATES

Figure 7 below provides the results of the scenarios that tested alternative dynamic rate structures, and direct load control (DLC) of equipment and EV chargers. As noted in key assumptions, the ODR scenario does include passive EV management, while the ODR+DLC scenario includes EV DLC for the share of market that opt-out of dynamic rates. Under these assessments the ODR scenario and ODR+DLC scenario provide similar potential savings. This result favours the ODR scenario without the addition of DLC programs. Overall, DLC offers little additional peak load reduction under the ODR+DLC scenario, but carries incentive, administration and controls infrastructure costs (detailed tables are available in the Appendix).

Figure 7: Achievable DR Potential for Scenarios 4-6 with optimized Corner Brook contract

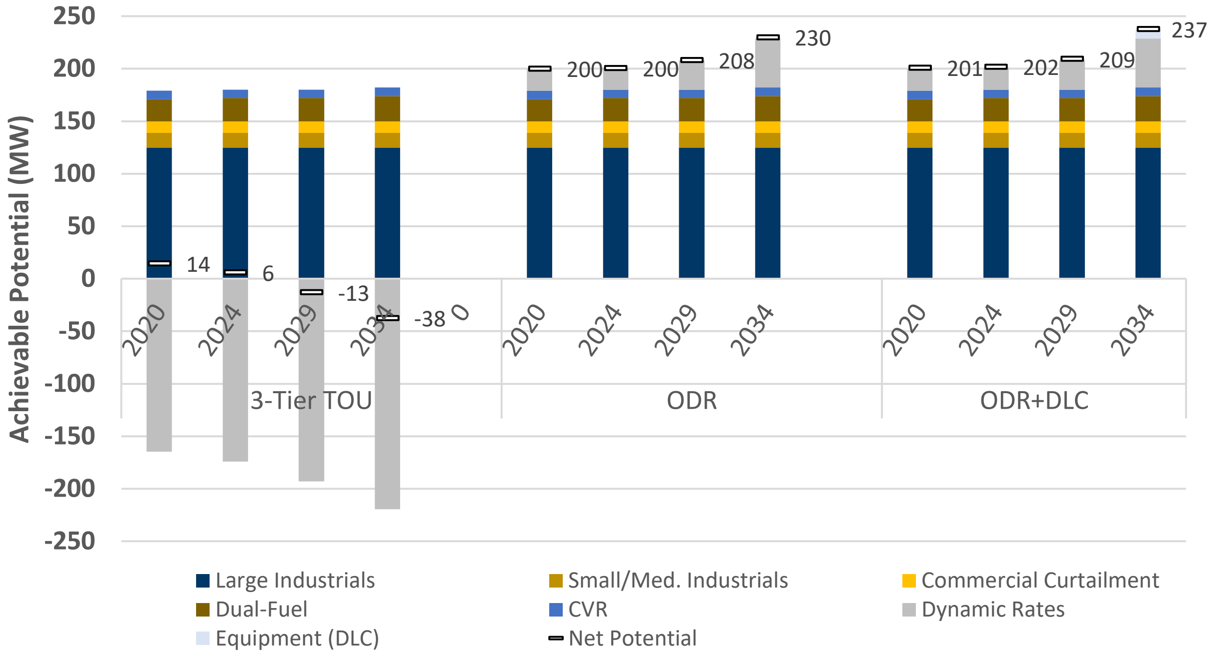


Figure 8 below shows the impact of each scenario-specific DR program on the peak day load curve. This analysis illustrates the impact of the 3-tier TOU scenario that creates new and higher peaks in the early morning and late evening, thereby offering a negative overall net DR potential. The ODR and ODR +DLC scenarios are largely super imposed, helping to flatten the load throughout the day.

Figure 8: Standard Peak Day impacts Scenario 4-6 (2020)

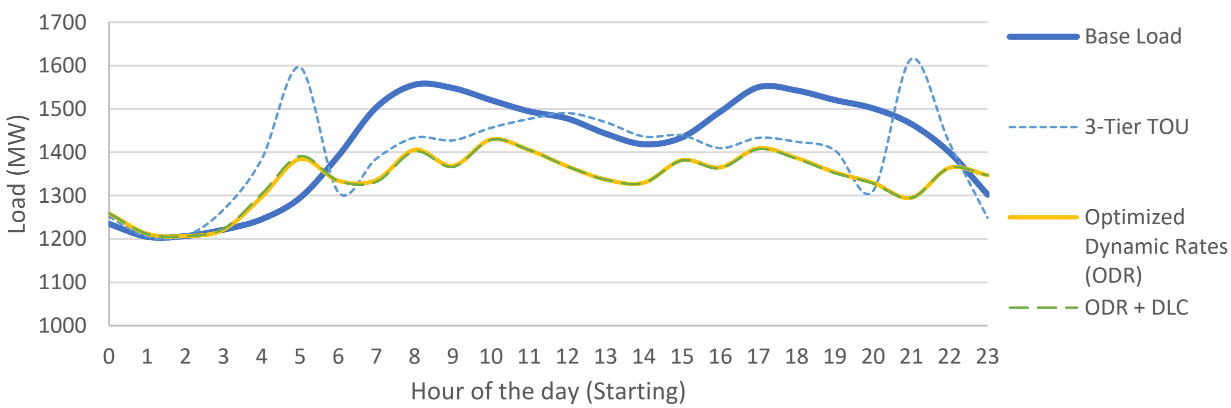
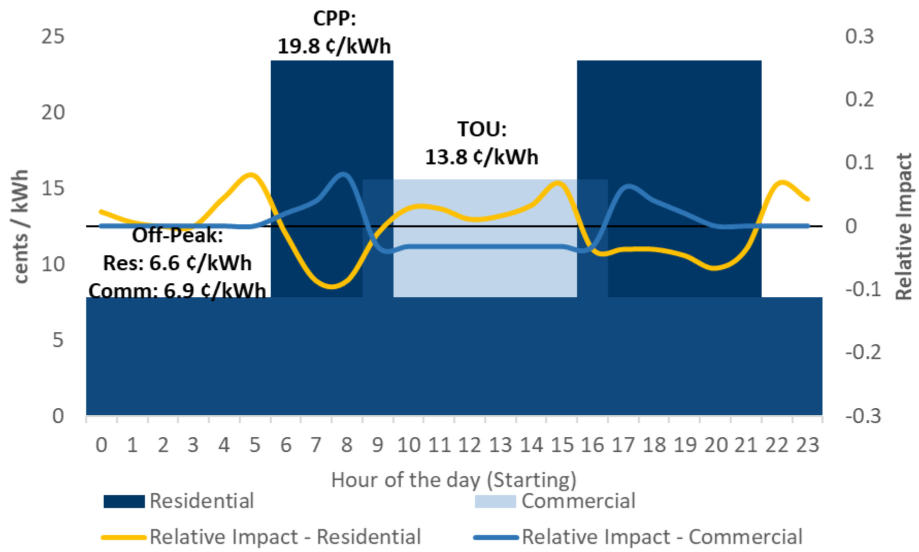


Figure 9 below provides the ODR program design that was arrived at through iterative application of the DR Model under varied rate designs. After testing various ODR designs, it was found that a 3:1 CPP program for residential customers effectively reduced the evening and morning peaks, while the TOU rates for commercial customers helped to avoid a new peak forming during the day time. In combination, these two programs were found to offer the largest overall peak reduction in an opt-out ODR program. Moreover, although the evening CPP event is six hours long, this is not an unrealistic duration as similar

CPP durations are or were implemented in other jurisdictions.[5] To account for the long duration, heating load driven peaks in NL, the assumed CPP reduction impact was reduced by 23% for the evening event.

Figure 9: ODR Design - Hourly Load Impacts (Residential CPP and Commercial TOU)[6]



DR PROGRAM COST-EFFECTIVENESS

Table 4 below shows cost effectiveness and net impact of each DR program under the most advantageous scenario (ODR and DLC), for each starting year (2020, 2024, 2029 and 2034) and assuming each program would run for a 10-year duration.

The results show that all programs can achieve cost effectiveness (based on a Program Administrator Cost Test (PAC) threshold of 1.0) by 2034. Note that residential DLC (the program including EV DLC) is only implemented in 2034. By then, there is limited room to expand the more cost-effective commercial DR program and the peak has shifted in the evening, making residential DLC a good program to target this new peak. The Dynamic Rates program cost-effectiveness assessment includes the full cost AMI deployment, and as such the benefits provided via the peak load reduction impacts do not appear to be sufficient to fully account for these costs in the earlier portion of the study period. AMI may offer some benefits that currently employed Advanced Meter Reading practices do not (such as reduced meter reading costs, two-way communications, and increased benefits from home energy feedback devices), which could help contribute to the business case for installing AMI across the IIC system.

5 Extended duration CPP program examples from Vermont and California are provided in the Appendix.
6 The optimized dynamic rates were designed to maintain a constant average bill in each sector, for existing residential and general service #2.1 rates.

Table 4: Best case DR Program (ODR+DLC Scenario) Peak Reduction Impacts (MW) and PAC results

Program Name	2020		2024		2029		2034	
	MW	PAC	MW	PAC	MW	PAC	MW	PAC
Equipment[7]	1.1	3.2	1.1	3.2	1.2	3.3	8.6	3.5
Dual Fuel[8]	21	1.7	22	1.8	22	1.9	24	2.1
TOU (Dynamic Rates including TOU & CPP)	21	0.5	21	0.5	28	0.7	47	1.2
Industrial Curtailment[9]	147	11.7	147	12.7	147	14.1	147	15.6

7 The Equipment program includes Residential DLC and Commercial DLC (including EV DLC).

8 Dual-Fuel program includes backup generators (BUGs) and dual fuel systems, as per the program description in Table F-16.

9 Includes both Large Industrial Curtailment (125 MW) and Small/Med Industrial Curtailment (22 MW).

SENSITIVITY 1: CORNER BROOK TOTAL CURTAILMENT HOURS PER YEAR

For each scenario we applied three possible constraints for the maximum total hours of Corner Brook curtailment in a given year, and assessed the impact of varying this on the distribution of IIC system peak hours (using historical hourly load data from 2015-2019 calendar years). From this we determined the number of hours that would exceed 1,590 MW, after accounting for the required capacity contingency requirements.[10] The 1,590 MW threshold was established as the estimated required capacity threshold below which the entire unallocated Maritime Link capacity could be dedicated to off-island sales (see Table 5 below).

Table 5: On-island capacity used to determine threshold for Maritime Link capacity requirements (Current capacity, with planned retirements removed)[11]

Resource	Capacity (MW)
On-Island Hydro Generation	1,132
Diesel Fueled Gas-fired Generation	124
Grid Connected Diesel-fired Generation	15
Grid Connected Oil-fired Generation	0
Labrador-Island Link[12]	820
Maritime Link Off-island Sales[13]	(500)
Net Total Capacity for IIC	***1,590 MW***

Our analysis then determined the number of hours per year that the total required IIC capacity exceeds 1,590 MW. This provides an indicator of further potential value that could be derived from DR programs on the IIC system such that lowering the number of hours that exceed the 1,590 MW threshold could increase the ability to sell the Maritime Link capacity.

Figure 10 below presents the portion of hours in a year where the system load would be expected to exceed the 1,590 MW threshold in 2020 under each DR program scenario, and under varied maximum hours of Corner Brook curtailment. Overall, the results indicate that regardless of the DR programs employed, approximately 6% of the hours per year would exceed the 1,590 MW threshold. Overall, it was found that the ODR scenario has the fewest hours that exceed the 1,590 MW threshold, but that the difference among the scenarios was not substantial.

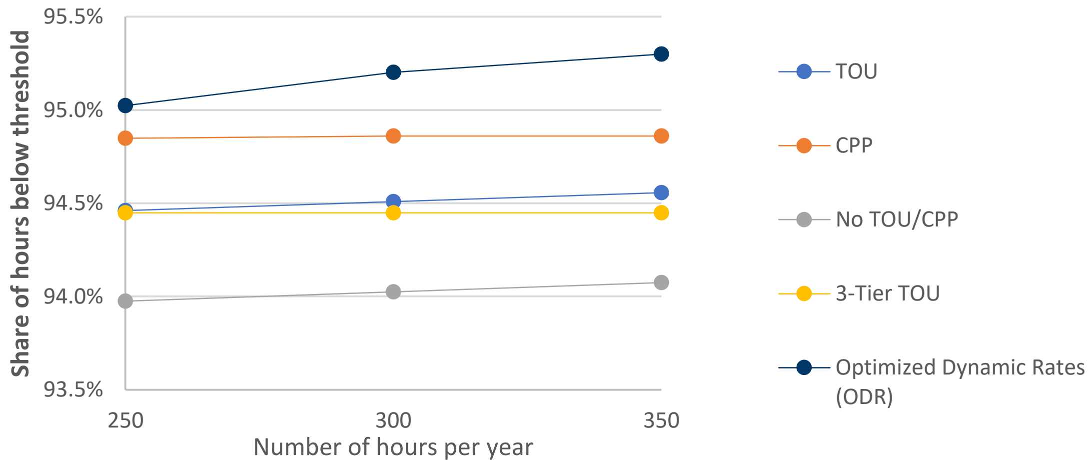
10 Estimated based on the maximum between 10-min and 30-min reserve (296 MW) or 16% of the peak load.

11 Retirements include Holyrood (oil), Harwoods and Stephenville (gas) generating facilities.

12 80 MW of forecasted losses, as per NL Hydro's 2018 Marginal Cost Study Update, on the Labrador-Island Link, yielding a net 820 MW of power for usage on the island.

13 The Maritime Link is presented as a capacity draw (negative value) to account for off-island sales.

Figure 10: Portion below 1,590 MW threshold per year (2020)



Further details on the ODR scenario, are presented in Table 6 and Table 7 below. Table 6 below presents the number of hours where load is below threshold, 0-5% above (1,590 – 1,670 MW), 5-10% above (1,670 – 1,750 MW) and above 10% threshold (> 1,750 MW). From this it can be observed that increasing the number of Corner Brook curtailment hours per year has practically no impact to lower the number of hours that exceed 1,750 MW in total IIC system required capacity (including buffers).

Table 6: IIC hourly load buckets (ODR Scenario – using 2015-2019 historical load curves)[14]

Corner Brook curtailment hours per year	< 1,590 MW	1,590 – 1,670 MW	1,670 – 1,750 MW	> 1,750 MW
350	8,348	312	88	11
300	8,340	318	91	12
250	8,324	327	97	12

Table 7: Portion of Corner Brook curtailment (ODR Scenario) that falls into sequential day events

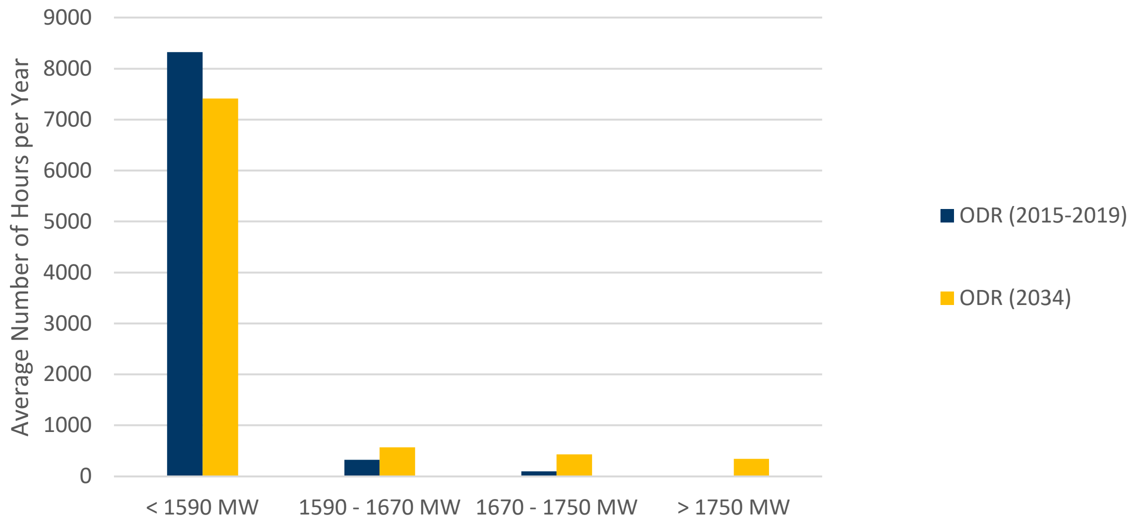
Number of days in a row	1	2	3	4+
Share of Corner Brook calls	59.5%	40.5%	0%	0%

We then applied the same assessment to the same historical load curves, but adjusted to account for customer growth, EV adoption and heat pump adoption in 2034. The results on the threshold analysis

14 Number of hours in a year might not add up to 8760 hours due to rounding.

are presented in Figure 11 below, which shows that the number of hours that will exceed the 1,590 MW will grow with time due to overall load growth on the IIC system.

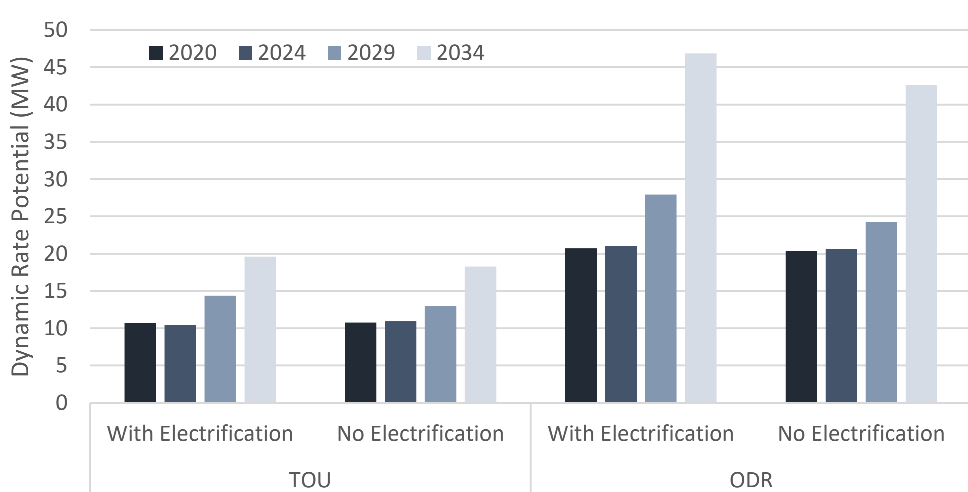
Figure 11: Number of hours by total IIC demand bin (250 hour maximum for Corner Brook curtailment)



SENSITIVITY 2: HEAT PUMP ADOPTION LOAD IMPACTS

In order to assess sensitivity to heat pump loads on peak days, potential demand reduction under the TOU and ODR scenarios was re-assessed without applying the fuel switching impact to the IIC utility load curve. The results in Figure 12 below present a comparison of the net demand reduction impact of the TOU and ODR programs, with and without the heat pump electrification peak load reduction being applied to the standard day load curve.

Figure 12: Electrification Load Curve Impact on Dynamic Rates



The results suggest that conversion to heat pumps will have little impact on the DR potential for the TOU and ODR programs. This is primarily because while HPs may somewhat change the amplitude of the annual peak, we assumed that they do not significantly change the peak day load curve shape (i.e. our study assumed that heat pumps would have a similar hourly load curve shape as electric baseboards). However, if it is found through Newfoundland Power's heat pump study that heat pumps exhibit a significantly different peak day shape from electric resistance, then it could change this result.

SENSITIVITY 3: $20M INVESTMENT SCENARIO FOR EV ADOPTION

To assess the viability of the ODR measures under a higher level of EV adoption, the ODR and ODR+DLC scenarios were tested using the $20M investment scenario from the initial report EV adoption analysis, coupled with the baseline heating electrification load curve impacts. Figure 13 below shows the cumulative EV sales to 2034 under the two EV adoption scenarios, which projects an additional 100,000 EVs under the $20M investment scenario, as compared to the baseline adoption. As a result, under the $20M investment scenario peak demand would increase by 231 MW (2034) over today's peak, as compared to 63 MW in the baseline EV adoption scenario. Moreover, the timing of the daily peak would be expected to move from the morning to the evening by 2024 in the $20M Investment scenario, compared to 2029 in the baseline scenario.

Figure 13: Forecasted EV Adoption – Baseline and $20M Investment Scenarios[15]

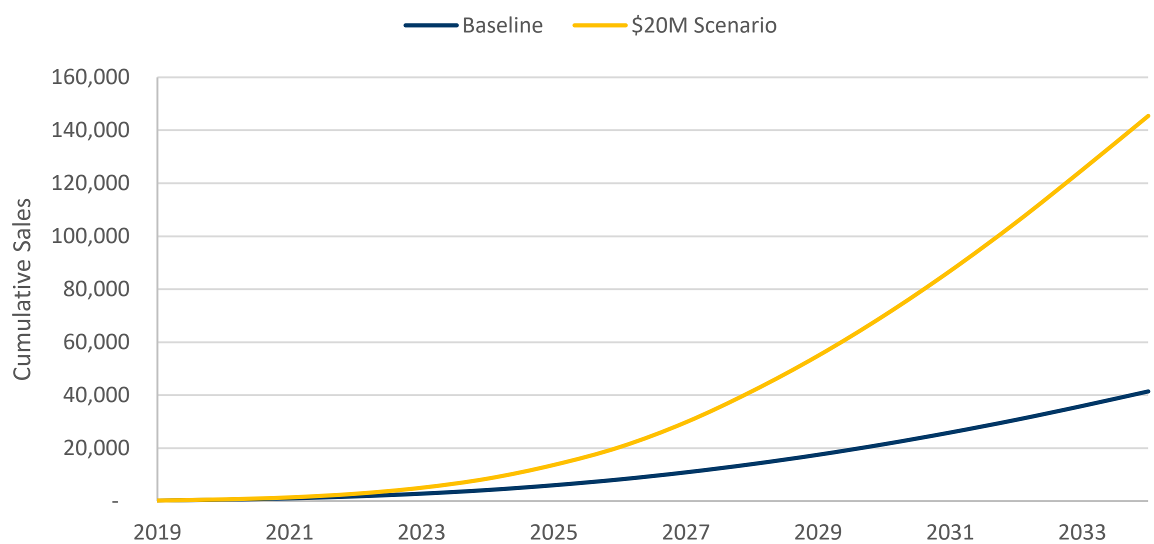


Figure 14 and Figure 15 below show the ODR scenario under the elevated EV adoption rates. Overall, the results show that the ODR scenario potential reached 45 MW by 2029 under more aggressive EV adoption, but then falls off as EV adoption increased further by 2034. This is because further EV adoption leads to a new peak appearing in the late evening thereby reducing the potential from the evening residential CPP program. It is possible that the residential CPP times could be adjusted to target this new peak, or that all

[15] Data from 2020-2034 Conservation Potential Study – Vol.2, Table F – 40, and Vol.1, Figure 6 – 3.

customers with EV chargers could be subject to time of use rates with steep evening price increases to mitigate this impact.

Figure 14: ODR Potential Under EV Adoption Scenarios

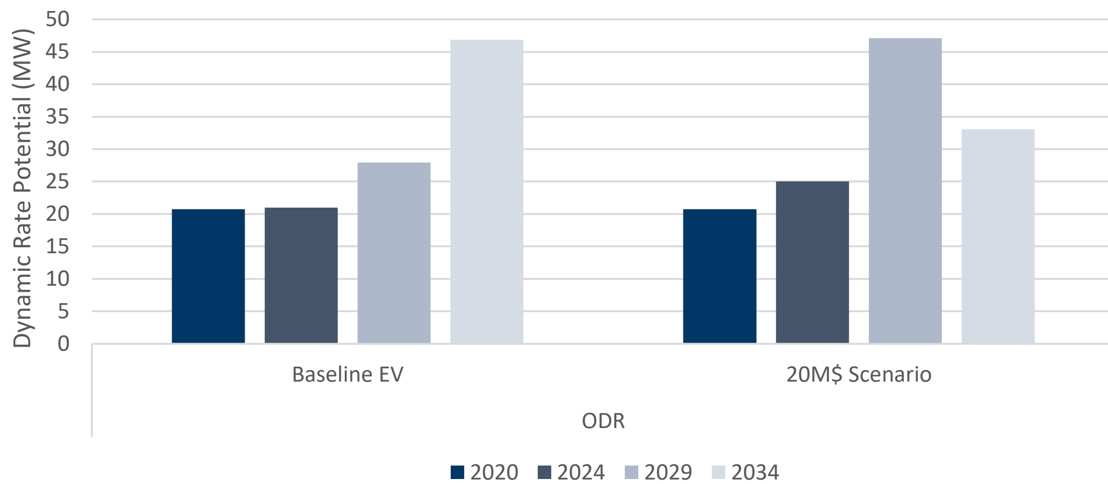
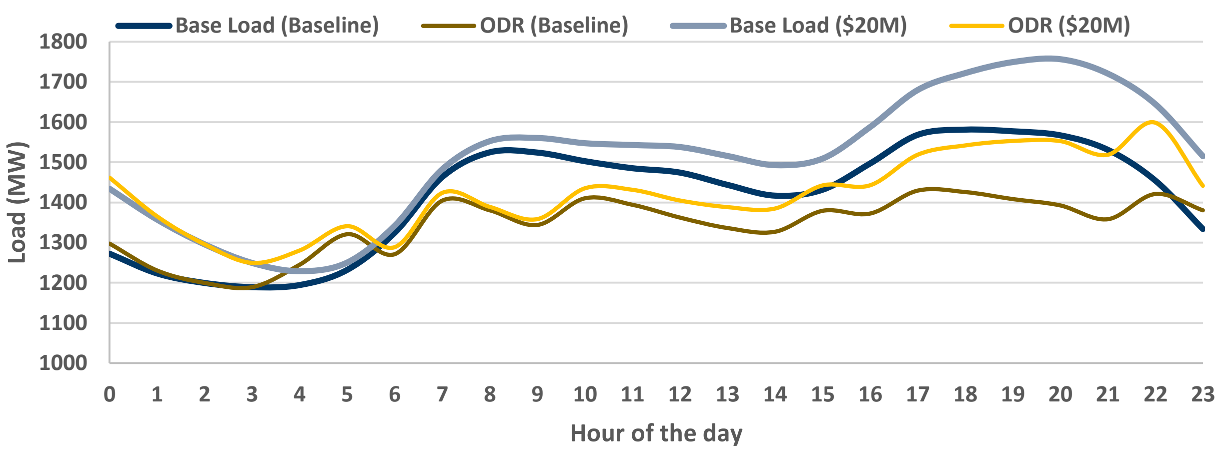


Figure 15: Peak Day Hourly Load Curve – ODR Scenario (2034)



Not shown in the figures above, we also assessed the additional peak demand potential from adding DLC measures to the ODR scenario. Similar to the baseline EV adoption, adding DLC alongside ODR has little impact over and above the ODR measures under the $20M investment scenario for EV adoption. This is because there is little DLC potential for appliances during the late evening peak event, and DLC program participation among EV owners who opted out of the ODR program is expected to be low. Of the 1.9 MW of DLC potential assessed in 2034, direct EV load management contributes the majority of 1.3 MW.[16]

These results suggest that a general dynamic rates approach to tackling the shifting peak load associated with EV adoption may not be the ideal option. Instead, targeting homes and businesses with EV chargers to engage in load management either through targeted EV rates (variable rates) or requiring new EV chargers to have enabled direct load control or smart charging capabilities may be the most effective way to mitigate the evening peak load associated with EV charging.

SENSITIVITY 4: EV CHARGING CONTROL STRATEGIES

Finally, we compared the potential for various EV load management strategies, and the results are presented in Table 8 below. Overall, while the direct control of EVs (as demonstrated in the No TOU/CPP scenario) provides the most peak reduction per enrolled vehicle, the dynamic rates approaches offer much broader participation via the assumed opt-out program requirement and as a result, the CPP and TOU approaches offer the highest EV peak reduction potential.[17] [18]

Table 8: Peak Reduction Potential (MW) for EV load management options (2034)

Scenario	TOU	CPP	EV DLC only	3-Tier TOU	ODR (Baseline Scenario)	ODR + DLC	ODR ($20M Scenario)
EV Load Management	21	30	8.7	29	18	19	66

While EV adoption under the current scenario is steadily increasing, as shown in Figure 13 above, the potential for EV load management does not follow this growth. This is because it is not until late in the study period (around 2029) that the EV adoption is sufficient to shift the current morning peak exhibited on the system to an evening peak. Because there is little EV charging demand in the morning, the potential peak load reduction attributable to EV load management is minimal up until 2029.

16 It should be noted that direct EV load management, without any dynamic rates, may offer significant potential 239 MW) as it is shown in Figure 6 – 18 of the 2020-2034 Conservation Potential Study – Vol.1. However, this analysis was conducted outside of the DR modelling assessment, and may over state the actual direct load control potential.

17 Under the dynamic rates program, we assumed all homes and businesses would be enrolled in an opt-out program model, with an 85% retention.

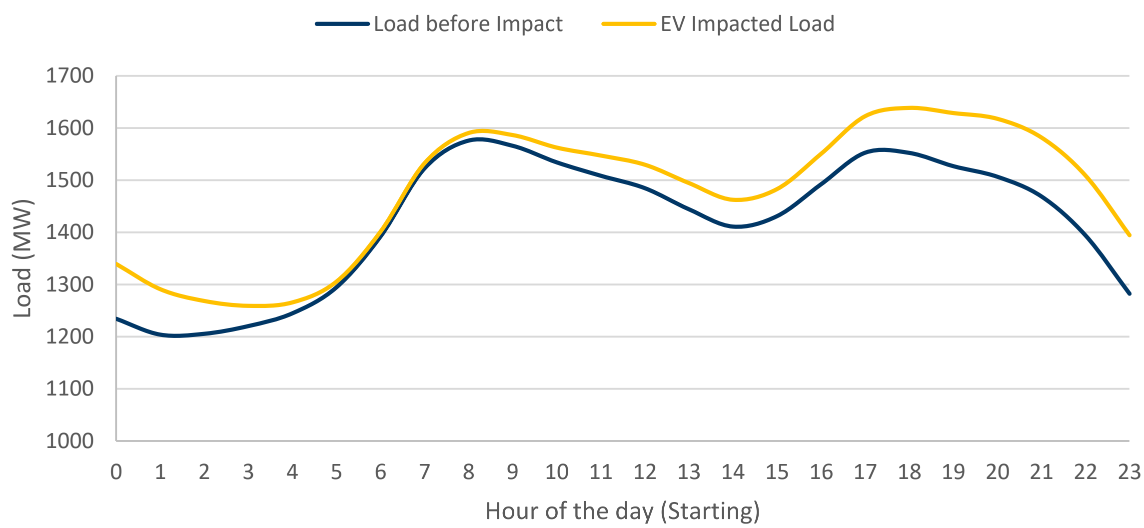
18 Table 11 to 14, in appendix, present the cost-effectiveness of various programs.

APPENDIX

2034 PEAK DAY LOAD CURVE IMPACTS FROM FUEL SWITCHING AND EV ADOPTION

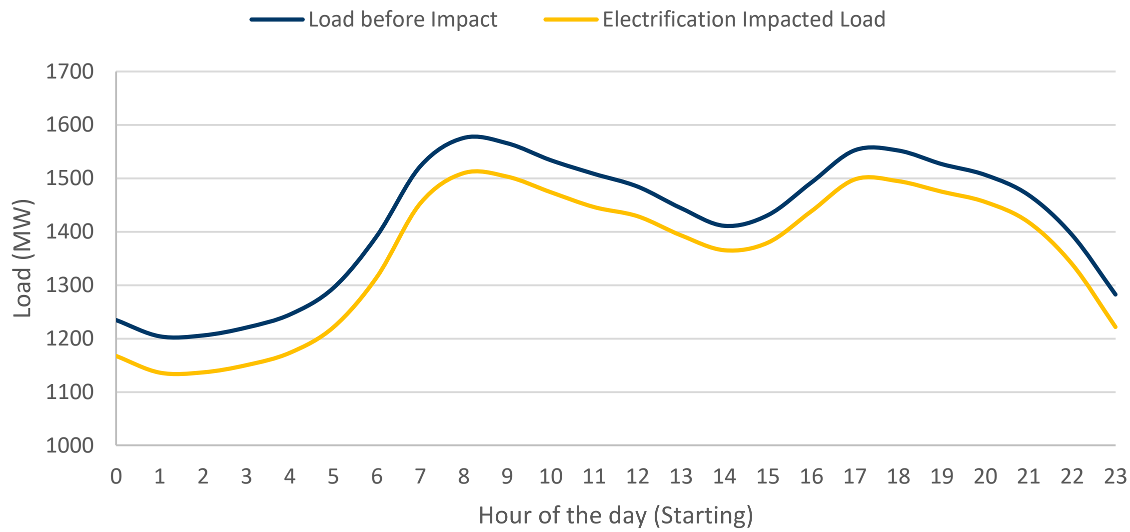
Electric vehicle impact in 2034 is presented in Figure 16. EVs increase, under the Baseline Scenario, the utility load by about 100 MW between 7:00 PM and 0:00 AM, while having a more limited impact (around 50 MW) during the day.

Figure 16: Impact of EV adoption on 2034 Standard Peak Day Load Curve (IIC)



Electrification, under the low scenario, reduces the overall electric demand in a relatively constant way with a reduction ranging from 50 to 75 MW over the standard peak day.

Figure 17: Impact of heating electrification on 2034 Standard Peak Day Load Curve (IIC)[19]



DETAILED PROGRAM RESULTS TABLES

Table 9 shows the demand savings achieved by programs, for each scenario studied. This data is also available graphically in Figure 2.

Table 9: DR Program Impacts (MW) under each scenario (2034)

Programs	TOU	CPP	No TOU/CPP	3-Tier TOU	ODR	ODR+DLC
Large Industrials	125	125	125	125	125	125
Small/Med. Industrials	14	14	14	14	14	14
Commercial Curtailment	11	11	11	11	11	11
Dual-Fuel	24	24	24	24	24	24
CVR	8	8	8	8	8	8
Optimized Dynamic Rates	20	- 1	0	-220	47	47
Equipment (DLC)	0.0	0.0	2.0	0.0	0.8	8.6

[19] The heating electrification component of the study included converting electric resistance heating to heat pumps. Due to the cost-effectiveness of this solution relative to the electrification of oil-fired heating, replacement of electric resistance heating represents the majority of heat pump adoption, thereby leading to an overall net reduction in the peak electric demand with time.

Tables below present the costs and benefits for each program by implementation years. They are presented for the ODR + DLC scenario, but the ODR scenario is also contained within these tables by simply not taking the Residential DLC and the DR Commercial programs into account. All costs and benefits are discounted using the 2020-2034 Conservation Potential Study discount rate of 3.92%. The program costing methodology is available in Appendix B (see DR Programs and Scenarios) of the potential study.

Table 10: Program costs/benefits – 2020

Program Name	Developmen t Costs	Fixed Annual Costs	Total Costs (Full Deployment)	Total Benefits (Full Deployment)	PAC Ratio
Residential DLC	$100,000	$75,000	$660,000	$0	0.0
DR Backup Power	$150,000	$75,000	$164,000,000	$281,000,000	1.7
DR Commercial	$150,000	$75,000	$1,070,000	$3,390,000	3.2
Dynamic Rates (TOU/CPP)	$88,600,000 [20]	$150,000	$139,000,000	$75,800,000	0.5
Industrial Curtailment	$150,000	$75,000	$33,500,000	$391,000,000	11.7

Table 11: Program costs/benefits – 2024

Program Name	Development Costs	Fixed Annual Costs	Total Costs (Full Deployment)	Total Benefits (Full Deployment)	PAC Ratio
Residential DLC	$100,000	$75,000	$660,000	$0	0.0
DR Backup Power	$150,000	$75,000	$170,000,000	$312,000,000	1.8
DR Commercial	$150,000	$75,000	$1,090,000	$3,530,000	3.2
Dynamic Rates (TOU/CPP)	$88,600,000	$150,000	$139,000,000	$75,600,000	0.5
Industrial Curtailment	$150,000	$75,000	$34,400,000	$439,000,000	12.7

Table 12: Program costs/benefits – 2029

Program Name	Development Costs	Fixed Annual Costs	Total Costs (Full Deployment)	Total Benefits (Full Deployment)	PAC Ratio
Residential DLC	$100,000	$75,000	$660,000	$0	0.0
DR Backup Power	$150,000	$75,000	$182,000,000	$353,000,000	1.9

[20] Including the full deployment of AMIs estimated in Appendix E of the 2020-2034 Conservation Potential Study.

DR Commercial	$150,000	$75,000	$1,120,000	$3,740,000	3.3
Dynamic Rates (TOU/CPP)	$88,600,000	$150,000	$139,000,000	$103,400,000	0.7
Industrial Curtailment	$150,000	$75,000	$35,700,000	$503,000,000	14.1

Table 13: Program costs/benefits – 2034

Program Name	Development Costs	Fixed Annual Costs	Total Costs (Full Deployment)	Total Benefits (Full Deployment)	PAC Ratio
Residential DLC	$100,000	$75,000	$1,070,000	$1,570,000	1.5
DR Backup Power	$150,000	$75,000	$189,000,000	$397,000,000	2.1
DR Commercial	$150,000	$75,000	$3,070,000	$11,010,000	3.6
Dynamic Rates (TOU/CPP)	$88,600,000	$150,000	$139,000,000	$173,600,000	1.2
Industrial Curtailment	$150,000	$75,000	$36,600,000	$570,000,000	15.6

LIMITING CONSTRAINTS FOR CORNER BROOK CONTRACT

In order to optimize the Corner Brook contract, current constraints were evaluated against the set of scenarios proposed in this study. The 12-hour limit of curtailment per day proved to be the most limiting factor in the integration with dynamic rates. Furthermore, both the CPP and No TOU/CPP scenario were within a few MW of exceeding the 12 hours, meaning that this extension could become beneficial for these scenarios with only small changes to the demand pattern.

Table 14: Resulting Peak based on Consecutive Hours of Curtailment in 2020 (MW)

Scenario	TOU	CPP	NO TOU/CPP	3-Tier TOU	ODR	ODR + DLC
12-hour curtailment	1,483	1,467	1,451	1,615	1,469	1,468
16-hour curtailment	**1,440**	1,467	1,451	1,615	**1,430**	**1,429**

LIST OF CPP WITH 6 HOURS OR MORE

Although there are many considerations to implementing a CPP program (ratepayer bill, low-income household impact, etc.), the table below shows a few CPP programs that were or are 6 hours or longer to confirm the possibility of an extended CPP event.

Table 15: List of CPP with a six-hour or longer duration

Utility	Duration	Source
Green Mountain Power	8h	https://greenmountainpower.com/wp-content/uploads/2018/03/Rate-14-TOU-and-Critical-Peak-Pricing-4.1.18.pdf
SDG&E	7h	https://pubs.naruc.org/pub.cfm?id=5378C352-2354-D714-518C-BD97831D7C0E
PG&E	6h	https://www.pge.com/includes/docs/pdfs/mybusiness/energysavingsrebates/demandresponse/cpp/dr_cpp_1858.pdf

CONSERVATION POTENTIAL STUDY VOL.1 – FIGURE UPDATE

This section provides updated figures from the initial potential study report, based on the findings from the further analysis presented in this addendum.

Figure 1-6 (Updated)

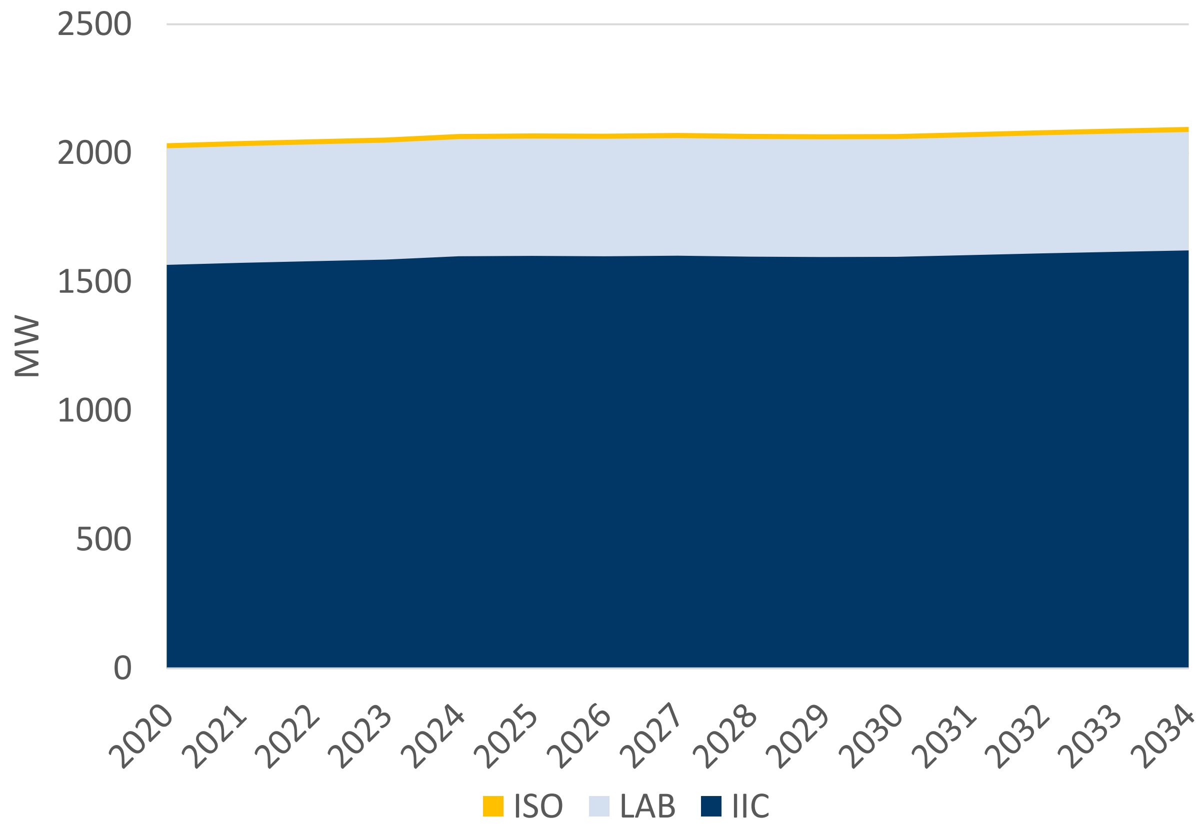
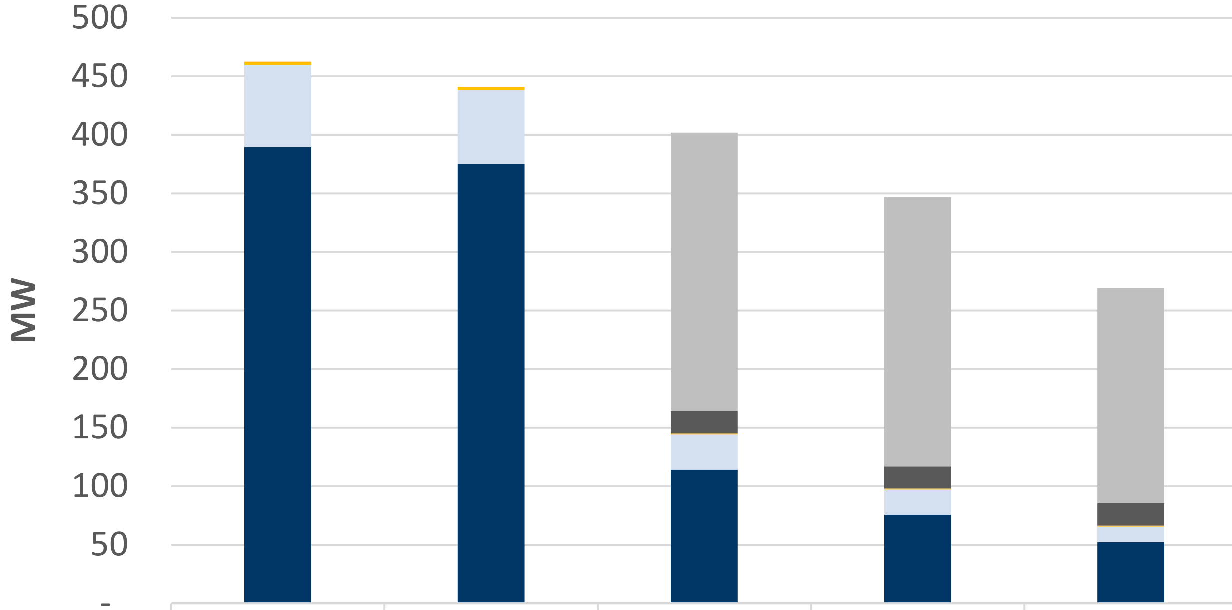
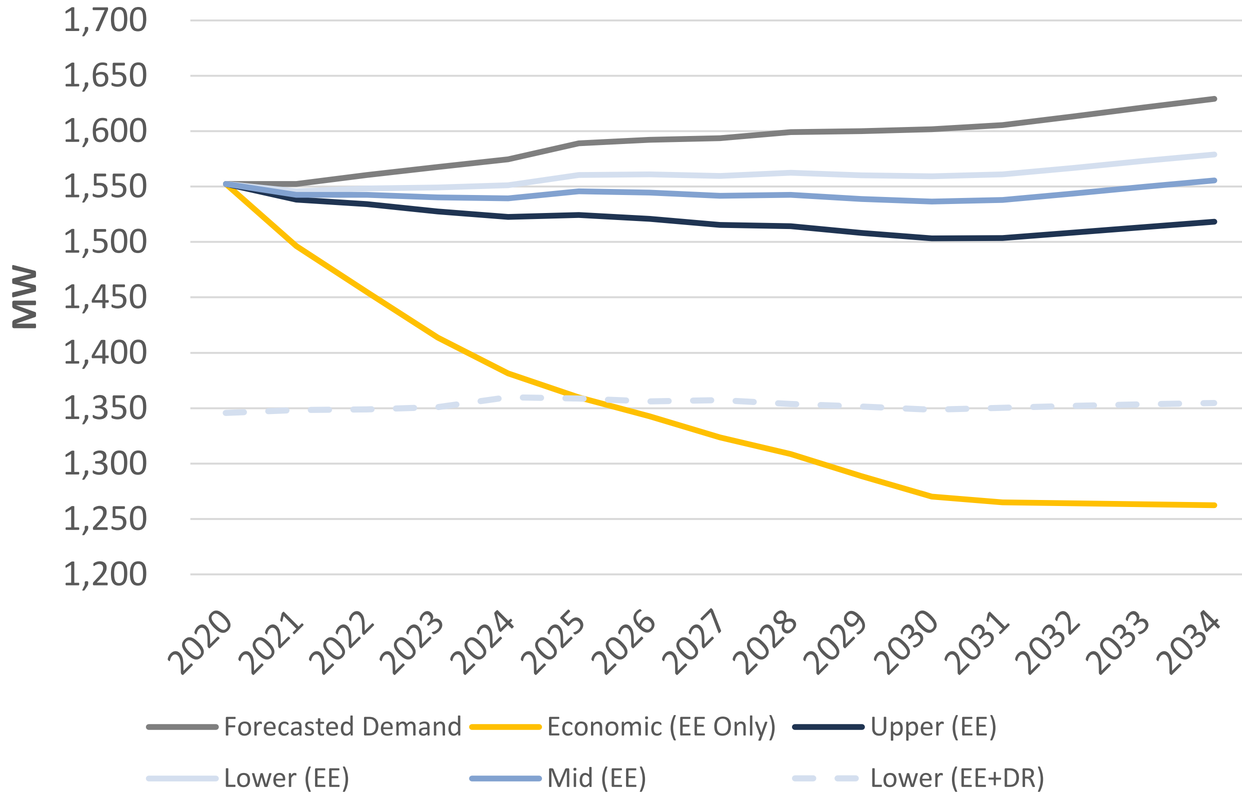


Figure 2-9 (Updated)



	Technical	Economic	Upper	Mid	Lower
IIC (DR)			238	230	184
LAB (DR)			19	19	19
ISO (EE)	3	3	1	1	1
LAB (EE)	70	63	30	22	14
IIC (EE)	390	375	114	76	52

Figure 2-10 (Updated)



Schedule F
2021 Plan Program Descriptions

Residential EV & Charging Infrastructure Program

Program Description

The objective of this program is to reduce the upfront capital cost of EVs and EV charging infrastructure. EVs typically have a higher up-front purchase cost than gasoline powered vehicles but lower ongoing operating and maintenance costs. The upfront cost of an all-electric vehicle is approximately $19,000 more than a standard gas-powered vehicle. This program will work in conjunction with the Federal rebate to further reduce the capital cost of an EV. The program components consist of at the cash rebates and a variety of education and marketing tools.

Once an EV is purchased, typically more costs are required to install Level 2 EV charging equipment at home. There may also be installation costs, including the cost of upgrades to wiring and electrical capacity. This program provides a rebate for qualifying Level 2 EV chargers to reduce this barrier to EV adoption. This program will also require customers to deploy connected Level 2 EV charging infrastructure at their homes to allow for future utility demand response programs.

Target Market: Residential

The program targets potential EV buyers and will reduce the overall cost of ownership, making the vehicle more economically attractive. Research shows that incentives will increase EVs load by as much as 16-32% in the short-term.

Eligible Measures

Both all electric and plug-in hybrid electric vehicles would be eligible. Qualifying network capable 240 V AC residential Level 2 chargers for EVs would also be eligible for rebate under this program.

Delivery Strategy

The program will be promoted through outreach, key partners and advertising delivered in conjunction with other residential EV marketing. Partnerships with dealerships will be central to delivery of this program. Dealers carry program marketing materials in-store to promote the rebates to customers and undertake training to educate staff about the program to further drive customer reach. The EV purchase incentive would be applied to the pre-tax purchase price.

Tools and tactics include website presence, tradeshows, retail point-of-sale materials, trade ally activities and advertising.

Residential EV & Charging Infrastructure Program

Market Considerations

Based on publicly available data, annual vehicle sales in Newfoundland and Labrador are estimated at approximately 37,000 vehicles. As of 2019, approximately 410,000 on-road vehicles were registered in the province, with 94% estimated to be LDVs. 66% of vehicles are estimated to be primarily for personal use.

Consumers are accustomed to having many options with respect to models, colors, and features when purchasing a new vehicle. The limited variety of EV models currently being manufactured and available at dealerships constrain adoption of EVs.

EV adoption faces a number of barriers such as the initial cost, access to charging and lack of customer understanding of the technology and awareness of the benefits.

Incentive Strategy

Incentives for this program include at the cash rebates. The Utilities will provide a rebate of $2,500 for an all-electric vehicle and $1,000 towards a plug-in EV. This reflects consideration of the incremental cost and the total cost of ownership with an EV. This program will work in conjunction with the Federal rebate to further reduce the capital cost of an EV.[1]

For residential EV charging infrastructure, an incentive will be provided toward the charger with a rebate of up to $500 of the pre-tax purchase price. Customers can apply online or by mail for this on-bill credit.

Program Monitoring & Evaluation

The program will be monitored for participation levels, program influence and cost effectiveness. Third party evaluations will be conducted after the first year of implementation and biannually during operation.

[1] This assumes the current federal incentive of $5,000 on a BEV and $2,500 on a PHEV covers a portion of this incremental cost (26% for an all-electric vehicle) and remains in place for the duration of the 2021 Plan.

Residential EV & Charging Infrastructure Program

Estimated Costs & Energy Savings						
	2021	**2022**	**2023**	**2024**	**2025**	**Total**
Estimated Costs ($000s)	515	1,067	1,896	2,061	2,964	8,503
Estimated Cumulative Energy Usage (GWh)	0.3	1.5	4.3	9.3	17.1	32.5
Modified Total Resource Cost						**1.9**

Commercial EV & Charging Infrastructure Program

Program Description

The objective of this program is to reduce the upfront capital cost of EVs for commercial customers adding EVs to their fleet of vehicles. EVs typically have a higher up-front purchase cost than gasoline powered vehicles but lower ongoing operating and maintenance costs. The upfront cost of an all-electric vehicle is approximately $19,000 more than a standard gas-powered vehicle. Currently, businesses that purchase EVs receive either a point of sale rebate or a tax credit from the Federal Government. The Utilities' program will work in conjunction with the Federal rebate to further reduce the capital cost of an EV. The program components consist of at the cash rebates and a variety of education and marketing tools.

Once an EV is purchased, typically more costs are required to install Level 2 charging equipment. There may also be installation costs, including the cost of upgrades to wiring and electrical capacity. This joint program provides a rebate for qualifying Level 2 EV chargers to reduce this barrier. This program will also require customers to deploy connected Level 2 EV charging infrastructure at their facilities to allow for future utility demand response programs.

Target Market: Commercial

The program targets potential EV buyers. This incentive would reduce the overall cost of ownership, making the vehicle more attractive from an economic standpoint. Research shows that incentives will increase EVs load by as much as 16-32% in the short-term.

Large companies or municipalities are likely to have fleet and transportation managers who will approach vehicle purchases by considering total cost of ownership which includes considering the vehicle purchase costs and ongoing operating costs. Buying decisions in larger companies are often heavily influenced by financial factors, budgets, company standards, etc. The purchase process generally involves defining the specifications of the vehicles wanted, then seeking out bids from vehicle manufacturers that meet these specifications.

Eligible Measures

Both all electric and plug-in hybrid electric vehicles would be eligible. Qualifying commercial network capable 240 V AC Level 2 chargers for EVs would also be eligible for rebate under this program.

Commercial EV & Charging Infrastructure Program

Delivery Strategy
The program will be promoted through outreach, key partners and advertising delivered in conjunction with other EV marketing. Partnerships with dealerships will be central to delivery of this program. Dealers carry program marketing materials in-store to promote the rebates to customers and undertake training to educate staff about the program. Outreach to commercial customers who have employee and fleet charging opportunities will be essential to this program. Marketing initiatives include partnering with trade allies in the automobile industry, particularly dealerships. Tools and tactics include website presence, tradeshows, retail point of sale signage, trade ally activities and advertising.
Market Considerations
Based on publicly available data, annual vehicle sales in Newfoundland and Labrador were estimated at approximately 37,000 vehicles. As of 2019, approximately 410,000 on-road vehicles were registered in the province, with 94% estimated to be LDVs. 34% of vehicles are estimated to be primarily for commercial use. Commercial EV adoption faces a number of barriers such as the initial cost, model availability, access to charging and lack of customer understanding of charging technology. This program will help to address all of these barriers.
Incentive Strategy
Incentives for this program include at the cash rebates. The Utilities will provide a rebate of $2,500 for an all-electric vehicle and $1,000 towards a plug-in EV. This reflects consideration of the incremental cost and the total cost of ownership with an EV. This program will work in conjunction with the Federal rebate to further reduce the capital cost of an EV.[2] For the charging infrastructure, the incentive will be provided toward the installation of a charger with a rebate of up to $3,000 off the pre-tax purchase price. Customers can apply online or by mail for this on-bill credit.

[2] This assumes the current federal incentive of $5,000 on a BEV and $2,500 on a PHEV covers a portion of this incremental cost (26% for an all-electric vehicle) remains in place for the duration of the 2021 Plan.

Commercial EV & Charging Infrastructure Program

Program Monitoring & Evaluation

The program will be monitored for participation levels, program influence and cost effectiveness. Formal evaluations will be conducted after the first year of implementation and biannually during operation.

Estimated Costs & Energy Savings

	2021	2022	2023	2024	2025	Total
Estimated Costs ($000s)	263	391	486	591	830	2,561
Estimated Cumulative Energy Usage (GWh)	0.1	0.4	1.0	2.4	4.8	8.7
Modified Total Resource Cost						**2.2**

Custom Electrification Program

Program Description
This program will be offered to help customers replace "standard" fossil fueled technologies with electric equivalent technologies that are more efficient. The Custom Electrification program would operate in a similar fashion as the Business Efficiency Program. Incentives are provided on an individualized basis for projects that are cost-effective from both the customer and utility perspectives.
Target Market: Commercial
This program targets business owners who have an interest in reducing their operating costs and their GHG emissions. The program includes a custom approach that evaluates projects on a case by case basis.
Eligible Measures
Eligible measures include any technology or process that could be electrified cost effectively from a customer and utility perspective. Projects could include the installation of mini-split heat pumps for water or space heating, electrification of business processes, dockside electrification or the purchase of electric fork lifts.
Delivery Strategy
The delivery strategy for this program is mainly through individual customer interactions. A complimentary walk-through audit helps customers identify electrification opportunities. Delivery of this program includes partnering with manufacturers, distributors, electrical contractors and service providers. The program creates business opportunities for trade allies to sell more efficient products. 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 trade ally and business association activities, such as workshops for distributors, contractors and building operators, website and advertising, such as in trade publications.

Custom Electrification Program

Market Considerations

Barriers to increased market penetration of these technologies include initial cost, awareness of the benefits of electrification and building ownership, budget and planning cycles, technical know-how and customer time constraints.

Incentive Strategy

Incentives for this program are designed to reduce the cost barrier, attract customer attention, provide technical and financial support and feasibility studies for electrification projects. The custom stream provides incentives based on project energy consumption of 15 cents/kWh. Rebates are paid on the energy use the customer is forecast to achieve in the first year of the project. Incentives of up to $50,000 per site help garner interest and lower customer project costs.

Program Monitoring & Evaluation

The program will be monitored for participation levels, service quality and cost effectiveness. Each incented custom project will have a measurement and verification plan to confirm energy use achieved is consistent with incentives paid. Third party evaluations will be conducted after the first year of implementation and biannually during operation.

Estimated Costs & Energy Consumption

	2021	2022	2023	2024	2025	Total
Estimated Costs ($000s)	174	304	249	360	351	1,438
Estimated Cumulative Energy Usage (GWh)	0.1	0.5	1.0	1.7	2.6	5.9
Modified Total Resource Cost						**2.1**

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 through takeCHARGE since 2009. Rebates for air sealing and duct insulation are new elements of this program and will be available beginning in 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 sealing 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, website, 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 initial cost, awareness of benefits, difficulties of renovating an existing living space, and a decreasing number of eligible participants. Additional barriers for the air sealing program are the availability of qualified blower door test inspectors and qualified air sealing contractors. Experience with the existing insulation program has shown participation to be responsive to awareness-building marketing activities.

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 insulation installed in the basement and crawl space and 50% of the cost of insulation installed in the attic. Rebate amounts are capped at $1,000 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 achieving a 10% improvement will receive a $100 rebate, customers achieving a 20% improvement will receive a $250 rebate and customers achieving improvement of 30% or higher will receive a $350 rebate. Upon completion of their project, and showing at least a 10% improvement, customers will also receive 50% of the cost of their blower-door test, up to $250. The maximum rebate a customer can receive is $600.

Duct insulation incentives will cover 50% of the cost to insulate ducts in unconditioned spaces 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 new program components will be conducted after the first year of implementation, with the full program being reviewed by an external consultant every three years during operation.

Insulation and Air Sealing Program

Estimated Costs & Energy Savings						
	2021	**2022**	**2023**	**2024**	**2025**	**Total**
Estimated Costs ($000s)	1,745	1,796	2,097	2,013	2,131	9,782
Estimated Cumulative Energy Savings (GWh)	54.4	60.6	67.0	73.8	80.8	336.6
Total Resource Cost						**6.6**

Thermostat Program

Program Description
The objective of this program is to encourage installation of programmable and high-performance electronic thermostats. Programmable and high-performance electronic thermostats allow customers to better control the temperature of their homes and to set it back during the night or while away. The program components include rebates, financing, and customer education. This program has been offered through takeCHARGE since 2009.
Target Market: Residential
This program targets residential customers. This includes existing and new homes that are a primary residence. Eligibility is limited to electrically-heated homes.
Eligible Measures
Eligible measures in this program include both programmable and high-performance electronic thermostats. Smart thermostats that can be controlled by a smart phone, tablet or computer are also eligible. All thermostats must have a setting precision of at least +/- 0.5 degrees Celsius.
Delivery Strategy
Program promotion will include partnering with retailers, electrical contractors, homebuilders and real estate professionals. The goal is to educate customers regarding the energy savings and comfort benefits of programmable and high-performance electronic thermostats. Tools and tactics include retail point-of-sale materials, website, tradeshows and community outreach. Rebates will be processed through online and mailed customer applications.

Thermostat Program

Market Considerations

Barriers to installation of programmable and high-performance electronic thermostats include lack of awareness of benefits, difficulty understanding how to program thermostats, reluctance to pay for an electrician to install the thermostats, and a decreasing number of eligible participants due to previous success of the program.

Incentive Strategy

Incentives for this program include rebates and financing. The rebate value is $5 per high performance electronic thermostat and $10 per programmable thermostat. These reflect the incremental cost of these measures above the baseline dial thermostat.

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 program evaluation will be completed every three years.

Estimated Costs & Energy Savings

	2021	**2022**	**2023**	**2024**	**2025**	**Total**
Estimated Costs ($000s)	567	453	507	528	475	2,530
Estimated Cumulative Energy Savings (GWh)	27.1	29.8	32.3	34.7	37.0	160.9
Total Resource Cost						**1.6**

Instant Rebates Program

Program Description
The objective of the Instant Rebates program is to increase home energy efficiency by increasing access to a variety of energy efficient technologies. The program, offers at-the-cash rebates at participating retailers during specific campaign periods during the year. This program has been in place since 2014.[3] Products under the Instant Rebate program help customers save on many end-uses including space heating, water heating, lighting and electronics. Many of these items are low-cost and easy to install.
Target Market: Residential
The target market is residential customers looking to make changes to decrease their overall energy usage. All customers can take advantage of this program, as long as they are purchasing an approved product. A variety of media such as TV, print, radio, online, website, as well as social media channels are used to engage customers and create program awareness.
Eligible Measures
Eligible measures include dimmer switches, ENERGY STAR® ceiling fans with lights, ENERGY STAR light fixtures, ENERGY STAR Dehumidifiers, ENERGY STAR LED light bulbs, faucet aerators, high performance showerheads, lighting timers, smart plugs, motion sensors, outlet and switch insulators, smart power strips, weather stripping, window insulation film and air purifiers.

[3] The Instant Rebates program is the ongoing component of the Small Technologies Program launched in 2014. The Small Technologies Program also included rebates on appliance and electronics. These rebates were available through online and mail-in application from 2014 to 2017. This component of the program was concluded in response to wide availability of high efficient models and forecasted decline of marginal costs. The program originally provided rebates on refrigerators, chest freezers, washing machines and televisions.

Instant Rebates Program

Delivery Strategy
This program is offered as an upstream rebate program with incentives applied when purchased at the cash. The program uses a combination of mass marketing, as well as retail partnerships and in-store promotion through the hiring of Retail Coordinators. Events at participating retailers help to keep customers informed of the rebates and associated energy savings benefits. Educational resources are also used to help customers understand how to select and install these energy efficient items.
Market Considerations
The technologies included in the program do not involve a major renovation and are typically easy to install. Barriers to the use of eligible products include lack of awareness of the products themselves and the benefits offered, such as smart power bars, and lack of understanding of how to install certain products, such as draft-proofing items.
Incentive Strategy
Product incentives are derived based upon the purchase price of the product and the associated energy savings benefits of the product, and as a result, vary depending on product type. Rebate amounts range from $1.00 to $30.00 per item. Incentives will continue to be offered at the cash, so customers will not have to apply for reimbursement.
Program Monitoring & Evaluation
The program will be monitored for participation levels, service quality, market saturation, and cost effectiveness, particularly as it relates to LED bulbs, which represent a majority of the products rebated. Socket saturation surveys and third-party evaluation will be conducted to inform the conclusion of the program. This will include determining LED saturation in homes and how influential the program is on customers' decisions to purchase these bulbs.

Instant Rebates Program

Estimated Costs & Energy Savings						
	2021	**2022**	**2023**	**2024**	**2025**	**Total**
Estimated Costs ($000s)	1,507	1,424	-	-	-	2,931
Estimated Cumulative Energy Savings (GWh)	76.6	81.3	78.7	77.3	77.1	391.0
Total Resource Cost						**1.7**

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. 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 associated 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 $175 for qualifying HRV units. This reflects the incremental cost of a more efficient unit. A $25 incentive is also provided to 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

	2021	**2022**	**2023**	**2024**	**2025**	**Total**
Estimated Costs ($000s)	199	202	254	241	245	1,141
Estimated Cumulative Energy Savings (GWh)	1.7	2.0	2.3	2.6	3.0	11.6
Total Resource Cost						**1.6**

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 customer's electricity usage to similar homes and their own consumption from the previous year. The Home Energy Reports and an online web portal provide tips and resources to facilitate energy use reduction. This program has been in place since 2016.

The Benchmarking program will be 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 home owners 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 the 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

	2021	**2022**	**2023**	**2024**	**2025**	**Total**
Estimated Costs ($000s)	1,023	957	976	997	1,017	4,970
Estimated Cumulative Energy Savings (GWh)	14.0	14.0	14.0	14.0	14.0	70.0
Total Resource Cost						**1.3**

Low Income 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 helps the Utilities reach low income customers with energy efficiency education through information included in the kits and online resources. The full cost of the kit, including delivery, will be incurred by the Utilities. This is a new program, starting in 2022.
Target Market: Low income residential
This program targets residential customers who meet the Utilities' low-income threshold. Renters and home owners will be eligible for this program regardless of heating source. Customers are limited to one kit per household.
Eligible Measures
The kits will include items such as LED light bulbs, high performance shower heads, faucet aerators and weatherstripping. The exact contents of each kit will be determined in conjunction with the selected program partner.
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.

Low Income Kit Program

Market Considerations

Barriers to installation of these measures for low income customers include the upfront cost, lack of awareness of benefits, and difficulty understanding how to install 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 after the first year of implementation and biannually during operation.

Estimated Costs & Energy Savings

	2021	2022	2023	2024	2025	Total
Estimated Costs ($000s)	60	470	569	494	574	2,167
Estimated Cumulative Energy Savings (GWh)	-	3.7	7.3	10.2	13.1	34.3
Total Resource Cost						**3.3**

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, thermostats, occupancy sensors, and more. The program also targets commercial customers with opportunities to reduce peak demand, with a focus on businesses who are replacing fossil fueled technologies with electric equivalent technologies.

Eligible Measures

There are three components of the BEP: (i) prescriptive rebates; (ii) custom energy 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, T8 LED tubes, T5 LED tubes, LED luminaires, LED parking lot lighting, LED exit signs, high performance showerheads, programmable thermostats, occupancy sensors, rooftop air source heat pump systems and pre-rinse spray valves.

Custom energy rebates involve takeCHARGE consulting with the customer on an energy saving project that is customized to individual customer circumstances. Incentives are provided on an individualized basis for projects that are cost effective from the customer and utility perspectives. 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. This component will evolve to support customers who are electrifying their facilities implementing demand management mechanisms, helping ensure that all customers benefit from the electrification of commercial buildings.

Business Efficiency Program

Delivery Strategy

The delivery strategy for this program is mainly through individual customer interactions. A complimentary on-site energy assessment helps customers identify efficiency and demand management opportunities.

Marketing for this program includes partnering with trade-allies such as lighting distributors and electrical contractors. The program creates business opportunities for trade allies to sell more efficient products.

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 and customer time constraints.

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/kWh for first year savings or project demand savings at $100 per kW per month over the December to March period for the first year of participation and $50 per kW each year for the life of the demand management system installed. Demand savings projects require a minimum of 50 kW savings to be sustainable over at least 5 years. The demand incentive may be updated to better support customers pursuing beneficial electrification. Incentives of up to $50,000 per site help lower customer project costs.

Incentives vary for the prescriptive measures. Rebates will be processed through mail-in and online submissions.

Program Monitoring & Evaluation

The program will be monitored for participation 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 program evaluation will be completed every three years.

Business Efficiency Program

Estimated Costs & Energy Savings						
	2021	**2022**	**2023**	**2024**	**2025**	**Total**
Estimated Costs ($000s)	1,816	2,092	2,183	2,267	2,591	10,949
Estimated Cumulative Energy Savings (GWh)	51.6	58.7	66.2	73.7	82.1	332.3
Total Resource Cost						**2.9**

Isolated Systems Community Program

Program Description

The objective of this program is to provide outreach, education and energy efficient products to home and business owners in Hydro's 40 remote diesel-system communities throughout Newfoundland and Labrador, free of charge.

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

Measures will range from efficient lighting products, water heating products, pipe insulation, hot water tank insulation, commercial LED exit signs, and others that may be applicable.

The Isolated systems lighting replacement program offers free of charge to commercial customers, the supply and install of new high-performance lighting technologies.

Delivery Strategy

Hydro has engaged a contractor to deliver this program. They use a number of delivery strategies, including hiring and training local representatives, to engage residential and commercial customers. Direct installation will be completed, whereby the customer receives the technology installed in their home or business at no cost. During the direct install visit, customers also receive information on energy usage and efficiency options.

Isolated Systems Community Program

Market Considerations

Availability and awareness of energy efficient technologies continues to be an issue in rural communities and often technologies available are at a higher price than in urban markets. This program will address the barriers of availability. Opportunities exist in electric hot water heating, plug load and behavior-based areas.

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 will provide the one on one interaction needed to assist these customers. The technologies included in the program do not involve a major renovation. This program will allow the utility to reach customers that may not have been able to participate in the other incentive programs.

Program Monitoring & Evaluation

The program will be monitored for participation level, service quality, and cost effectiveness. A representative sample of direct installs will be surveyed for confirmation of continued installation and use. An evaluator will be involved to develop quality assurance guidelines and procedures and ensure they are aligned with evaluation standards and best practices.

Estimated Costs & Energy Savings

	2021	**2022**	**2023**	**2024**	**2025**	**Total**
Estimated Costs ($000s)	999	999	999	999	999	4,995
Estimated Cumulative Energy Savings (GWh)	11.2	11.8	12.2	12.5	12.8	60.5
Total Resource Cost						**1.4**

Isolated Business Efficiency Program

Program Description
The objective of the Isolated Business Efficiency Program is to help commercial customers increase their electrical energy efficiency by providing incentives on energy efficient options for existing facilities. The program provides supports to encourage customers to implement projects customized to their own facilities. This program is offered to business customers in Hydro's isolated diesel and L'Anse au Loup system areas.
Target Market: Commercial
This program targets business owners and property managers in Hydro's isolated diesel and L'Anse au Loup systems who have an interest in making their businesses more energy efficient. The program includes a custom project approach and also rebates for specific measures, such as high-performance lighting and Air Source Heat Pumps.
Eligible Measures
The custom stream allows customers to obtain rebates for almost any energy efficiency measures that result in economical electrical energy savings. The program excludes alternative energy and fuel switching. The specific measures eligible for per unit rebates have included programmable thermostats, occupancy sensors, high performance showerheads, and LED wall packs. In 2016, LED screw-in lamps, High Bay LED fixtures, Electrically Commutated Motors for Evaporator fans, Cold climate air source heat pump systems and Low Flow Pre-rinse spray valves were added to the prescriptive list of incentives.

Isolated Business Efficiency Program

Delivery Strategy

The delivery strategy for this program is mainly through individual customer interactions. The custom track involves a walkthrough audit and feasibility analysis to determine savings and eligible incentives. This allows for a wide range of eligible technologies and projects.

Marketing for this program includes partnering with lighting manufacturers, distributors, electrical contractors and lighting service providers as key market influencers and allies. The program will create business opportunities for trade allies to sell more efficient products.

The program will also target commercial property owners through direct marketing. Tools and tactics will include trade ally and business association activities, such as workshops for distributors, contractors and building operators, and a website. Demonstration projects will be selected from program participants.

Market Considerations

Barriers to efficiency in the commercial market include financial and human resource concerns. Incentives will assist in making energy efficiency upgrades more accessible. Human resource concerns are around awareness and knowledge of the technology options as well as time to develop the business case for retrofit projects.

The isolated systems have additional challenges with access to products and access to specific technical skill sets in the evaluation of projects and technology. Hydro's program staff will assist in addressing these gaps.

Incentive Strategy

Incentives for this program are designed to reduce the cost barrier, attract customer attention and provide technical and financial support for energy audits and feasibility studies. The custom stream provides incentives based on project energy savings at the lesser of $0.4/kWh for first year savings or 80% of eligible project costs.

Incentives vary for the prescriptive measures. Rebates will be processed through mail-in and online customer applications.

Isolated 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

	2021	2022	2023	2024	2025	Total
Estimated Costs ($000s)	1.0	1.0	1.0	1.0	1.0	5.0
Estimated Cumulative Energy Savings (GWh)	0.9	1.0	1.1	1.2	1.3	5.5
Total Resource Cost						**1.5**

Industrial Energy Efficiency Program

Program Description

The objective of this program is to improve electrical energy efficiency in a variety of industrial processes. The program components include financial incentives based on energy savings and other supports to enable industrial facilities to identify and implement efficiency and conservation projects. This program is a custom program to respond to the unique needs of Hydro's industrial customers, rather than a prescriptive technology approach.

Target Market: Industrial

This program targets existing, transmission level, industrial customers served by Newfoundland and Labrador Hydro.

Eligible Measures

Eligibility of projects is based on engineering review and confirmation of estimated energy savings impact. 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 utility takes the role of facilitator and consultant in providing methods for industrial customers to complete project proposals and implement approved projects.

This program was initially launched as a three-year pilot program in 2009, with the first project applications being submitted in 2011, and closed to new projects in 2013. The industrial pilot was reviewed in 2014 by an external party for performance; the review indicated the program matched or exceeded performance of comparable industrial CDM programs relative to the size of the industrial sector in the Newfoundland and Labrador market. The program was officially re-launched as an ongoing program in 2015, with the same structure as the pilot program.

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.

The lifecycle for each program transaction will be measured in months rather than weeks because of the need for review, contract development, budgeting and implementation timelines, and post-installation evaluation. This type of program requires that facilities have financial and business stability to continue operations for a time period appropriate to achieve cost effective savings.

Incentive Strategy

Incentives for this program include an initial comprehensive energy audit for the site, funding assistance for feasibility studies, and financial assistance for project implementation based on energy savings.

Program Monitoring & Evaluation

The program will be regularly monitored for participation level, service quality, and cost effectiveness, including engineering review and inspection of all projects and assessment of long-term impact on customer processes.

Industrial Energy Efficiency Program

Estimated Costs & Energy Savings[4]						
	2021	**2022**	**2023**	**2024**	**2025**	**Total**
Estimated Costs ($000s)	224	224	224	224	224	1,120
Estimated Cumulative Energy Savings (GWh)	31.0	31.0	31.0	31.0	31.0	155.0
Total Resource Cost						-

[4] Hydro reminds its five 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 TRC cannot be forecast but all proposed projects must result in a positive TRC.

Schedule G
Stakeholder Consultation Summary

Stakeholder Consultation Summary

The planning cycle for customer programming is a continuous process involving stakeholder consultation at each phase.

The Utilities conducted a number of customer surveys and stakeholder interviews and workshops to inform the development of the Electrification, Conservation and Demand Management Plan 2021-2025 ("the 2021 Plan").

An overview of these customer and stakeholder consultations is provided in Table G-1.

Table G-1
2021 Plan Customer and Stakeholder Consultations

Residential End Use Survey	600 customers were surveyed.[1] The information gathered was used to assess potential electricity savings and electrification opportunities.
Commercial End Use Survey	403 facilities were surveyed.[2] This research provided information on commercial energy use in the province.
Customer Barrier Survey	666 residential customers and 150 commercial customers were surveyed to determine the largest barriers to technology adoption.[3]
Stakeholder Interviews and Workshops	Industry experts were interviewed to help quantify the potential and possible barriers, for electrification and CDM in the province.[4]
Government and Key Stakeholder Consultation	The Utilities currently participate in the Electrification Working Group formed by the Department of Energy, Innovation and Technology to inform the development of the Province's rate mitigation plan. Prior to this, Utilities worked with the Provincial Government and other stakeholders to assess opportunities and address challenges associated with increasing EV adoption through the Provincial Office of Climate Change's Electric Vehicle Working Group.

Initiatives in the 2021 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 throughout program design and the implementation of the 2021 Plan. This collaborative process enables the Utilities to continuously evaluate market trends, advances in technology, customer barriers and program effectiveness.

---

[1] The Residential End Use Survey was completed by MQO Research in 2017.

[2] The Commercial End Use Survey was completed by ICF Consulting Canada using mail out surveys to commercial customers. Surveys were completed over 2017 and 2018.

[3] The Customer Barrier Survey was completed by Dusky Energy Consulting in 2019.

[4] Workshops were held to consult with stakeholders such as commercial customers, trade allies, customer group representatives and retail partners.

Schedule H
Marginal Cost Projection of the Island Interconnected System
2021-2040

Table H-1 Marginal Cost Projection For the Island Interconnected System 2021-2040				
		Energy		Capacity
	Winter On-Peak ($/MWh)	Winter Off-Peak ($/MWh)	Non-Winter ($/MWh)	($/kW-Yr.)
2021	78	64	27	326
2022	79	64	29	333
2023	70	56	26	341
2024	68	56	27	350
2025	67	56	29	358
2026	74	63	29	364
2027	77	66	30	372
2028	79	69	34	380
2029	83	72	39	390
2030	85	73	40	398
2031	87	75	41	406
2032	88	76	42	414
2033	90	78	43	422
2034	92	79	44	431
2035	94	81	44	439
2036	96	83	45	448
2037	98	84	46	457
2038	100	86	47	466
2039	102	88	48	475
2040	104	89	49	485

Table H-1 shows the most recent marginal cost forecast based on projections by Newfoundland and Labrador Hydro in April 2020. 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. on weekdays is considered on-peak hours. Off-peak hours occur after 11:00 p.m. until 7:00 a.m. and include weekends.

Schedule I
Electrification and CDM Program Economic Evaluation Practices

Table I-1 shows the primary economic tests used by utilities to evaluate CDM programs in Canadian jurisdictions.

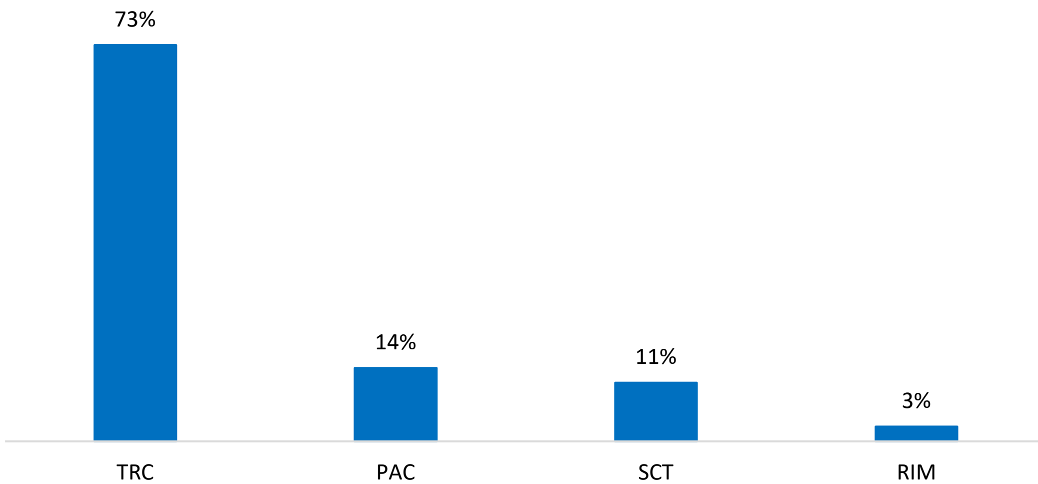
Table I-1
Current Canadian Utility Practice
CDM Economic Evaluation Practices

Province	**Primary Economic Test**				
	TRC[1]	PAC[2]	RIM[3]	PCT[4]	SCT[5]
British Columbia[6]	X[7]				
Ontario	X[7]				
Nova Scotia[8]	X				
Manitoba[9]		X			
Quebec[10]	X				
Prince Edward Island[11]		X			
New Brunswick[10]		X			
Total	**4**	**3**			

1 Total Resource Cost Test (“TRC”). The TRC evaluates programs from the perspective of the customer and the utility. It includes the costs and benefits experienced by the utility system, plus costs and benefits to program participants.
2 Program Administrator Cost Test (“PAC”). The PAC evaluates programs from the perspective of the utility. It includes the costs and benefits experienced by the utility system.
3 Ratepayer Impact Measure (“RIM”). The RIM evaluates programs to provide an indication of their impact on rates. This test includes all of the costs and benefits included in the PAC, plus estimates of the utility lost revenues created by programs.
4 Participant Cost Test (“PCT”). The PCT evaluates programs from the perspective of the participant. This test includes all impacts on the program participants, but no other impacts.
5 Societal Cost Test (“SCT”). The SCT evaluates programs from the perspective of society as a whole. This test includes the costs and benefits experienced by society such as health benefits and GHG emission reductions.
6 British Columbia considers PAC and RIM as secondary tests.
7 British Columbia and Ontario use a modified TRC that includes non-energy benefits that are not traditionally included in the TRC.
8 Nova Scotia considers PAC as an informative test.
9 Manitoba also considers the utility net present value and levelized utility cost.
10 Quebec and New Brunswick consider the PCT a secondary test.
11 Prince Edward Island uses the PAC at the portfolio and program level as the primary test. The TRC is used as a secondary test at the program level.

Chart I-1 shows the percent of U.S. states which use some of the economic tests in Table I-1.[12]

Chart I-1
Current American Utility Practice
CDM Economic Evaluation Practices
(% of States)



n=37

[12] Research conducted by the American Council for an Energy Efficient Economy (January 2020) "*Evaluation, Measurement, & Verification Database". The Societal Cost Test ("SCT")* includes benefits such as environmental benefits and improved health and comfort.

Table I-2 shows the primary economic tests used to evaluate electrification programs in North American jurisdictions.

Table I-2
Current North American Utility Practice
Electrification Economic Evaluation Practices

Jurisdiction	**Rate Impacts Assessment**[13]	**Overall Cost Assessment**[14]	**Not assessing cost effectiveness**
Arizona			X
British Columbia			X
California		X[15]	
Kansas			X
Maryland			X
Massachusetts			X
Missouri		X	
New York		X	
Ohio	X	X	
Oregon	X	X[15]	
Rhode Island	X	X	
Utah			X
Vermont		X	
Washington			X
Total	**3**	**7**	**7**

13 Rate Impacts Assessment includes utilities that are using the RIM test for electrification programs.
14 Overall Cost Assessment includes utilities that are using the TRC, SCT or a test created by the utility specifically for electrification that evaluates programs from the perspective of the customer, the utility and the ability to meet policy objectives.
15 California and Oregon are using multiple tests in the Overall Cost Assessment category to evaluate cost effectiveness.

Schedule J
Utility Investment Models for Electric Vehicle Charging Infrastructure

Utility Investment Models for EV Charging Infrastructure

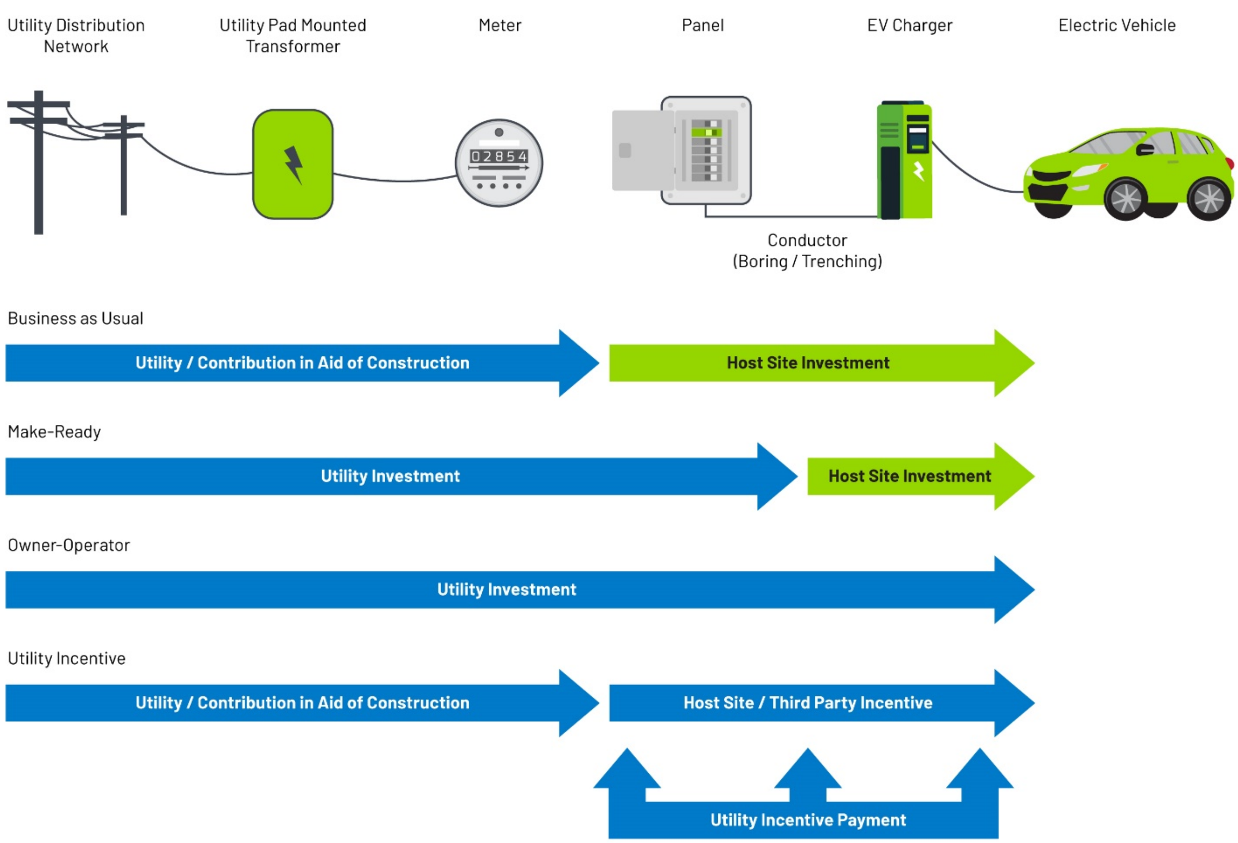
A lack of sufficient EV charging infrastructure is a barrier to widespread EV adoption. A comprehensive charging network is needed to eliminate customer concerns about reaching their destination and to enable long-distance travel.

Variables to consider when determining the most effective utility investment model for a jurisdiction include siting, the capacity of the distribution system, the local EV charging infrastructure market and EV adoption rate. The appropriate investment model may vary across a utility's service area and over time.

Utility investment in EV charging infrastructure can have numerous benefits including: (i) increasing the pace and scale of charging infrastructure development, (ii) maintaining reliability and minimizing grid impacts, and (iii) providing more equitable access to charging infrastructure for all EV drivers.

There are three primary models for utility investment in EV charging infrastructure: (i) make-ready, (ii) utility charging network; and, (iii) utility incentive. Figure J-1 below shows the three common models for utility investment in EV charging infrastructure, compared to a business as usual investment.[1]

Figure J-1



1 MJ Bradley and Associates, *Utility Investment in Electric Vehicle Charging Infrastructure: Key Regulatory Considerations*, 2017.

Utility Investment Models for EV Charging Infrastructure

Business as Usual: When a customer requests a new service connection, the Utilities follow a Board approved methodology to determine the required utility and customer contributions. The customer investment is referred to as a contribution in aid of construction ("CIAC"). The utility typically funds and owns the infrastructure up to the customer meter and the customer owns all assets behind the meter.

Make-Ready Model: The make-ready model includes the installation of electrical infrastructure to enable customers to purchase and install DCFC. This may include upgrades to transformers and service capacity, installing meters or running new service drops to specific areas of a host site, such as in a parking lot at a workplace.

Investment in make-ready infrastructure helps reduce the costs associated with customer DCFC infrastructure. Make-ready costs are typically a large portion of the capital costs of an installation, at about 30%–40%.[2]

Utility Owner-Operator Model: The utility owns and operates all components of the EV charging infrastructure, also referred to as a Utility Charging Network. A utility owner-operator would also oversee other program components, including marketing and host site recruitment, pricing and ongoing operations and maintenance.

Utility Incentive Model: The utility administers and provides rebates for EV charging infrastructure.

The 2021 Plan: Utility Investment in EV Charging Infrastructure

The Utilities are proposing investment in the make-ready and utility owner-operator models.

Table J-1 shows the number of DCFC's forecast to be installed from 2021 through 2025 as a result of utility investment in the 2021 Plan.

Table J-1
DCFC's Installed
2021 through 2025

	2021	2022	2023	2024	2025	Total
Make-ready	-	1	3	5	6	15
Utility Charging Network	18	11	3	5	4	41
Total	**18**	**12**	**6**	**10**	**10**	**56**

Through utility investment in DCFCs in the 2021 Plan, a total of 56 fast chargers are expected to be in place in the province by 2025.[3]

2 Chris Nelder and Emily Rogers, *Reducing EV Charging Infrastructure Costs*, Rocky Mountain Institute, 2019, p. 23.

3 To maximize impacts of investments, existing federal programs will be leveraged to reduce utility costs associated with DCFC infrastructure deployment.

Schedule K
2021 Plan Pilot Descriptions

Custom Fleet Pilot Program

A significant portion of the forecast electricity demand associated with EVs in the province is expected to come from commercial vehicles. However, in the early years, medium-duty vehicles ("MDVs") and heavy-duty vehicles ("HDVs") uptake is expected to lag due to low model availability and higher upfront capital costs for EVs compared to conventional vehicles. Barriers to increased market penetration of MDVs, HDVs and buses include initial cost, awareness of benefits, market gaps for service and maintenance of EVs, the investment required for charging infrastructure and EV model availability.

The Custom Fleet Pilot Program targets commercial customers interested in the electrification of MDVs, HDVs and buses. The objective of this pilot is to reduce the costs associated with electrification of vehicles which are not eligible under the prescriptive electrification programs. It will also allow the Utilities to understand the unique barriers associated with electric MDVs, HDVs and bus adoption. This program will also enable the Utilities to work with participants to pilot initiatives that encourage off-peak charging.

Due to the custom nature of the Custom Fleet Pilot Program, eligible measures vary and depend on the needs of the interested participants. The pilot program components may include support through feasibility and fleet optimization studies, financial support for EVs and charging infrastructure, and technical advice. Incentives for each customer will vary depending on the potential load electrified.

Table K-1 shows the estimated costs, the number of vehicles and the additional electrified load added to the system associated with the Custom Fleet Pilot Program.

Table K-1
Custom Fleet Pilot Program
Costs, Vehicles and Electrified Load

	2021	2022	2023	2024
Costs ($000s)	295	605	857	1,038
# of Vehicles	2	3	5	7
Electrified Load (MWh)	104	126	230	275

EV Demand Response Pilot Program

By 2034, EV adoption is forecast to increase load and potentially change the Utilities' load shape. The 2020–2034 Potential Study suggests that in the near term, research and evaluation be used to understand these potential impacts and explore mitigation strategies. Managed or controlled EV charging will be key to limiting utility demand impacts thereby reducing customer costs. Managed charging allows EVs to be charged at times and at power levels that benefit both customers and the Utilities.

The EV Demand Response Pilot Program targets customers who are existing or potential EV owners and will be charging at home with a level 2 charger. The objective of this pilot program is to assess demand response measures to determine their ability to shift peak loads, customer acceptance and cost effectiveness. The pilot program will collect EV charging information showing the load profile of charging operation and the impact on the distribution system.

The EV Demand Response Pilot Program will consider various technologies that help reduce charging at times of system peak such as smart chargers and direct load controllers. Vehicle analytics will be used to understand charging behaviour and the impact of EV charging demand on the electrical system. Incentives may be a combination of equipment purchase and a monthly participation credit, based on allowing the utility to manage EV charging. The pilot program will provide EV charging information showing the load profile of charging operations.

Table K-2 shows the estimated costs, the number of vehicles and the demand reduction associated with the EV Demand Response Pilot Program.

Table K-2
EV Demand Response Pilot Program
Costs, Vehicles and Demand Reduction

	2022	2023	2024
Costs ($000s)	573	316	258
# of Vehicles (Cumulative)	75	125	125
Demand Reduction (kW)	96	159	159

Small Business Direct Install Pilot Program

Small business owners face a number of barriers to making energy efficient upgrades including competing monetary demands and lack of time. They may also be unsure of where to start and of the benefits of these upgrades. To help overcome these participation barriers, this pilot program facilitates the direct installation of energy efficient measures at no cost to the customer.

The Small Business Direct Install Pilot Program targets Rate 2.1 commercial customers interested in making their business more energy efficient. The objective of this pilot program is to assess the cost effectiveness of a provincial direct install program. The pilot will also help businesses identify larger energy efficient upgrades which could be eligible for incentives through the Business Efficiency Program and no-cost ways to save on their energy costs.

The pilot program will be delivered through a third-party vendor who will supply eligible energy saving measures, coordinate customer visits, and install eligible measures. Eligible measures will include both water saving and lighting technologies.

Table K-3 shows the estimated costs, the number of participants and the energy savings associated with the Small Business Direct Install Pilot Program.

Table K-3
Small Business Direct Install Pilot Program
Costs, Participants and Energy Savings

	2021	2022	2023
Costs ($000s)	24	434	468
# of Participants	0	270	270
Cumulative Energy Savings (GWh)	0.0	1.0	2.0

Heat Pump Load Research Pilot Program

The Heat Pump Load Research Pilot Program began in the fall of 2019, with the objective of determining the impacts of the growing popularity of residential mini-split heat pumps ("MSHP") on Newfoundland Power's electricity system. The results will be used to determine the potential impact of MSHPs on system load shapes with an emphasis on system peak. The results will also serve to inform future conservation and demand management program design and customer education initiatives.

To accomplish these objectives, metering equipment was installed in 264 homes throughout Newfoundland to monitor electricity consumption. Approximately half of participating homes have a MSHP (the treatment group) while the other half are heated with an electrical resistance heating system (the control group). A meter was installed to monitor the MSHP in all treatment group homes, so that the electricity consumption of the MSHP could be recorded in addition to that of the whole house. The pilot program is expected to conclude in the spring of 2021.

Table K-4 shows the estimated costs and the number of participants associated with the Heat Pump Load Research Pilot Program.

Table K-4
Heat Pump Load Research Pilot Program
Cost and Participants

	2019	**2020**	**2021**
Costs ($000s)	462	202	129
# of Participants	264	264	264

Schedule L
Electrification, Conservation and Demand Management Program Forecasts

Table L-1 Electrification Programs Energy Usage Estimates: 2021 – 2025 by Sector (GWh)						
	2021	**2022**	**2023**	**2024**	**2025**	**Total**
Residential						
EV & Charging Infrastructure Incentives	0.3	1.5	4.3	9.3	17.1	32.5
Total Residential Portfolio	**0.3**	**1.5**	**4.3**	**9.3**	**17.1**	**32.5**
Commercial						
EV & Charging Infrastructure Incentives	0.1	0.4	1.0	2.4	4.8	8.7
Custom Commercial	0.1	0.5	1.0	1.7	2.6	5.9
Total Commercial Portfolio	**0.2**	**0.9**	**2.0**	**4.1**	**7.4**	**14.6**
Total Portfolio	**0.5**	**2.4**	**6.3**	**13.4**	**24.5**	**47.1**

Table L-2 Electrification Programs Program Cost Estimates: 2021 – 2025 by Sector ($000s)						
	2021	**2022**	**2023**	**2024**	**2025**	**Total**
Residential						
EV & Charging Infrastructure Incentives	515	1,067	1,899	2,061	2,964	8,506
Total Residential Portfolio	**515**	**1,067**	**1,899**	**2,061**	**2,964**	**8,506**
Commercial						
EV & Charging Infrastructure Incentives	263	391	486	591	830	2,561
Custom Commercial	174	304	249	360	351	1,438
Total Commercial Portfolio	**437**	**695**	**735**	**951**	**1,181**	**3,999**
Total Portfolio	**952**	**1,762**	**2,634**	**3,012**	**4,145**	**12,505**

Table L-3 **Conservation Programs** **Energy Reduction Estimates: 2021 – 2025 (Includes Prior Years' Savings)** **by Sector** **(GWh)**						
	2021	**2022**	**2023**	**2024**	**2025**	**Total**
Residential						
Insulation and Air Sealing Program	54.4	60.6	67.0	73.8	80.8	336.6
Thermostat Program	27.1	29.8	32.3	34.7	37.0	160.9
ENERGY STAR Window Program	9.9	9.9	9.9	9.9	9.9	49.5
Coupon Program	0.2	0.2	0.2	0.2	0.2	1.0
Isolated Systems Community Program	10.0	10.5	10.9	11.2	11.5	54.1
Small Technology Program	76.6	81.3	78.7	77.3	77.1	391.0
HRV Program	1.7	2.0	2.3	2.6	3.0	11.6
Benchmarking	14.0	14.0	14.0	14.0	14.0	70.0
Low Income	0.0	3.7	7.3	10.2	13.1	34.3
Block Heater Timer Program	0.3	0.3	0.3	0.3	0.3	1.5
Total Residential Portfolio	**194.2**	**212.3**	**222.9**	**234.2**	**246.9**	**1,110.5**
Commercial						
Isolated Systems Community Program	1.2	1.3	1.3	1.3	1.3	6.4
Isolated Systems Business Efficiency Program	0.9	1.0	1.1	1.2	1.3	5.5
Business Efficiency Program	51.6	58.7	66.2	73.7	82.1	332.3
Total Commercial Portfolio	**53.7**	**61.0**	**68.6**	**76.2**	**84.7**	**344.2**
Industrial						
Industrial Energy Efficiency Program	**31.0**	**31.0**	**31.0**	**31.0**	**31.0**	**155.0**
Total Portfolio	**278.9**	**304.3**	**322.5**	**341.4**	**362.6**	**1,609.7**

Table L-4
Conservation Programs
Demand Reduction Estimates: 2021 – 2025 (Includes Prior Years' Savings)
by Sector
(MW)

	2021	2022	2023	2024	2025	Total
Residential						
Insulation and Air Sealing Program	18.2	20.7	23.4	26.2	29.1	29.1
Thermostat Program	4.1	4.2	4.3	4.4	4.4	4.4
ENERGY STAR Window Program	3.1	3.1	3.1	3.1	3.1	3.1
Coupon Program	0.0	0.0	0.0	0.0	0.0	0.0
Isolated Systems Community Program	3.3	3.5	3.6	3.7	3.8	3.8
Small Technology Program	18.2	19.1	18.6	18.2	18.2	18.2
HRV Program	0.5	0.6	0.7	0.8	0.9	0.9
Benchmarking	1.7	1.7	1.7	1.7	1.7	1.7
Low Income	0.0	1.0	2.1	2.9	3.8	3.8
Block Heater Timer Program	0.0	0.0	0.0	0.0	0.0	0.0
Total Residential Portfolio	**49.1**	**53.9**	**57.5**	**61.0**	**65.0**	**65.0**
Commercial						
Isolated Systems Community Program	0.1	0.1	0.1	0.1	0.1	0.1
Isolated Systems Business Efficiency Program	0.4	0.4	0.5	0.5	0.5	0.5
Business Efficiency Program	9.3	10.7	12.2	13.9	15.7	15.7
Total Commercial Portfolio	**9.8**	**11.2**	**12.8**	**14.5**	**16.3**	**16.3**
Industrial						
Industrial Energy Efficiency Program	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**
Total Portfolio	**59.6**	**65.8**	**71.0**	**76.2**	**82.0**	**82.0**

Table L-5
Conservation Programs
Program Cost Estimates: 2021 – 2025
by Sector
($000s)

	2021	2022	2023	2024	2025	Total
Residential						
Insulation and Air Sealing Program	1,745	1,796	2,097	2,013	2,131	9,782
Thermostat Program	567	453	507	528	475	2,530
Isolated Systems Community Program	999	999	999	999	999	4,995
Small Technology Program	1,507	1,424	-	-	-	2,931
HRV Program	199	202	254	241	245	1,141
Benchmarking Program	1,023	957	976	997	1,017	4,970
Low Income	60	470	569	494	574	2,167
Total Residential Portfolio	**6,100**	**6,301**	**5,402**	**5,272**	**5,441**	**28,516**
Commercial						
Isolated Systems Business Efficiency Program	71	71	71	71	71	355
Business Efficiency Program	1,816	2,092	2,183	2,267	2,591	10,949
Total Commercial Portfolio	**1,887**	**2,163**	**2,254**	**2,338**	**2,662**	**11,304**
Industrial						
Industrial Energy Efficiency Program	**224**	**224**	**224**	**224**	**224**	**1,120**
Total Programs Portfolio	**8,211**	**8,688**	**7,880**	**7,834**	**8,327**	**40,940**

Table L-6 **Electrification Programs** **Modified Total Resource Cost Test Results** **by Sector**	
	mTRC Results
Residential	
EV & Charging Infrastructure Incentives	1.9
Commercial	
EV & Charging Infrastructure Incentives	2.2
Custom Commercial	2.1

Table L-7 **Conservation Programs** **Total Resource Cost Test Results** **by Sector**	
	TRC Results
Residential	
Insulation and Air Sealing Program	6.6
Thermostat Program	1.6
Isolated Systems Community Program	1.4
Instant Rebates Program	1.7
HRV Program	1.6
Benchmarking	1.3
Low Income	3.3
Commercial	
Isolated Systems Business Efficiency Program	1.5
Business Efficiency Program	2.9
Industrial	
Industrial Energy Efficiency Program	-[1]

[1] Hydro reminds its five transmission-level customers annually of the availability of this program, but the 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 TRC cannot be forecast but all proposed projects must result in a positive TRC.

Schedule M
Letters of Support

Newfoundland Labrador

Government of Newfoundland and Labrador
Department of Industry, Energy and Technology
Office of the Minister

DEC 16 2020

Mr. Kevin Fagan
Vice President
Newfoundland and Labrador Hydro

Mr. Byron Chubbs
Vice President
Newfoundland Power

Dear Mr. Fagan and Mr. Chubbs:

RE: Electrification, Conservation and Demand Management Plan: 2021-2025

Thank you for sharing your companies' Electrification, Conservation and Demand Management Plan for 2021-2025, along with the accompanying presentation. The plan indicates the province's utilities are taking actions to begin addressing the electrification, and conservation and demand management (CDM) recommendations in the Board of Commissioners of Public Utilities Rate Mitigation Options and Impacts Report. The Board's report demonstrated clearly that these action areas have excellent potential to assist with our rate mitigation efforts.

The evidence in the report suggests progress to date and a path forward for these areas. Given the external market conditions for non-firm energy sales in recent years, domestic load growth is a promising market for our energy sector, provided that load growth can occur in a cost-effective manner that can limit or reduce peak demand growth that would trigger costly new power supply infrastructure. We were pleased to see a role for CDM to help avoid these higher demand peaks.

We also note the plan concludes that dynamic rates for managing load growth does not appear to be a favourable tool at this time. Rate design, time of use rates, and critical peak pricing continue to interest our Government and hold promise for the future and we hope to see additional research and further progress in these areas over time.

We also note there are other areas of interest over the longer term that we look forward to advancing as economic feasibility allows. While the plan demonstrates that light duty vehicles are promising markets for our renewable electricity in the short and medium terms, our Government believes heavy duty and marine transportation are longer-term markets worthy of further examination. We look forward to working with you in these areas in the future.

Newfoundland Labrador

I sincerely appreciate your efforts to share your work to date to advance electrification and CDM and look forward to working together to make our province a leader in these areas.

Sincerely,

ANDREW PARSONS, QC
Minister of Industry, Energy and Technology
Attorney General

Alliance for Transportation Electrification

November 30, 2020

Krista Langthorne, Manager
Business Development
Newfoundland Power
55 Kenmount Road
St. John's, NL A1B 3P6
Canada

Re: Support of the 2021-25 Electrification, Conservation and Demand Management Plan

Dear Ms. Langthorne:

I have had a chance to review your draft plan for the above-mentioned five year period which you shared with the Alliance describing an expansion of the previous CDM (Conservation and Demand Management) plans and programs to transportation electrification end use cases. Overall, I believe you and your team at NL Power have done a great job in developing a comprehensive analysis at the electric vehicle (EV) and its projections, the important role of the utility as well as other EV market actors, and trying to meet the public policy goals of both the federal and provincial governments. More specifically, I think you have been responsive to the request from the Board (PUB) in February 2020 that requested you to develop such a study. Based upon our experience in reviewing similar transportation electrification and decarbonization plans in other North American jurisdictions, I believe that you have both met this requirement for a holistic, well-founded Plan that is similar to best practices in these jurisdictions. This should provide a solid basis for constructive dialogue with EV stakeholders.

Background and Introduction

The Alliance for Transportation Electrification, a 501(c)(6) non-profit corporation, is led by utilities, electric vehicle (EV) infrastructure firms and service providers, automobile manufacturers, and EV charging industry stakeholders and affiliated trade associations. We started with 20 organizations at the launch in early 2018. By taking a "big tent" approach to advance the industry, we have grown rapidly to include about 50 national dues-paying members and affiliated organizations. We are actively involved in over twenty regulatory and other state and Provincial proceedings in North America today.

General comments

Increasing the adoption of EVs and building out the transportation electrification (TE) infrastructure has become both a goal of the federal government as well as the Province, as the Plan states in the Background section. This is an important public policy imperative today in many (if not most) jurisdictions across North America today, not only from the environmental perspective of reducing GHGs as well the harmful tailpipe emissions that especially during this period of Covid-19 have shown deleterious and disproportional impacts on certain neighborhoods and communities. But an increasing number of observers realize that this fundamental transformation of the vehicle and transportation industries is happening, both for light-duty and medium and heavy-duty vehicles, and there are important economic and international competitiveness issues related to the automobile industry in the NAFTA countries of Canada, the United States, and Mexico. Yet, Newfoundland and Labrador are not unique in that transportation emissions constitutes about 32 percent of overall GHG emissions; this percentage ranges from 30 to 45 percent in general across North American jurisdictions depending on specific generation and fuel mix for electricity. Accordingly, the Plan does a fine job in taking on this broad public policy imperatives while suggesting broad outlines of programs/tariffs and accompanying budgets to carry these out.

Secondly, it makes sense to the Alliance to build on the successes of the existing programs in energy efficiency (the CDM programs) and integrating them in to a more coherent whole. While the Alliance is not familiar with the previous CDM programs over the past decade, many of our utility members are also approaching demand-side management (DSM) programs in a more integrated and holistic way. Obviously, traditional DSM programs are developed to reduce system peak in a cost-effective method and therefore reduce energy consumption, while electrification programs, and EVs in particular will increase electricity use over time. But the critical nature of controlling loads on the demand side, and especially make them more responsive and flexible, has become quite apparent in the evolving grid of the future.

Third, as stated earlier, the Plan you have developed is consistent with several of the other "best practice" TE plans by other utilities, as well as policy guidance by certain Public Utility Commissions, in North America jurisdictions. This is a very dynamic field recently as more EVs are publicly announced, and as more utilities, vendors, and host sites are moving forward with plans in the TE field. You have attached a good summary of the various initiatives in North America on electrification, and mostly on light-duty vehicle electrification. But even this static description does not do justice to the number and breadth of utility initiatives. Recently, for example, Portland General Electric (PGE) in Oregon, Avista Utilities in Washington, and Xcel Energy in both Colorado and Minnesota have developed similar TE plans and received approval from their Commissions, and are moving ahead now with specific programs and tariffs which flow from those Plans. Your Plan of NL Power can be considered to be in a similar best practice category that includes comprehensive and solid analysis on not only transportation electrification potential, but also the long-term conservation potential study (CPS).

Finally, since the Board and the Province have insisted you assess the rate migration options in the context of the Muskrat Falls Project in its final report in February 2020, I believe you have made your best efforts to examine the potential and likely impacts of greater TE on revenues and rates over this period of time. In fact, I believe your estimates in the study are appropriately cautious, since the Alliance believes that the Upper Case (more robust) projections of EV adoption are more likely in the five to ten-year time horizon. But our members firmly believe that greater EV adoption will result in greater revenue requirements, and if we can collectively achieve managed charging to move these loads off-peak, such benefits can be shared with all customers.

Specific comments

Regarding the market projections for EV sales in the Plan, we think it is always appropriate to develop a range of forecasts for the adoption of these vehicles and consumers over the time horizon, and longer out to 2035. You appear to have utilized a range of market projections and forecasts that have been developed globally and for North America, and then brought them down to the Provincial and your service territory level. The Alliance tends to put more in the bullish range of forecasted EV adoption (Upper Scenario in your Plan), and therefore we would think that adoption by 2025 approaching the 145,000 vehicles, and increased electricity sales of 720 GwH, will be more likely.

Secondly, your Plan rightfully points out the critical importance of "managed charging" in various parts of the plan, including the striking table on p. 12. If there is one table that you and the EV stakeholders should focus on as specific programs and tariffs are developed in the months ahead, it would be this table showing a $283 million differential in costs between unmanaged and managed charging (namely, the difference in costs out to 2034 between $431 million in unmanaged charging and $147 million for managed charging). Of course, managed charging is a broad term that is really flexible load management (that apply to other DSM measures and DERs as well) means that can include: dynamic or time-varying rates of the utility; demand response techniques to reduce system peak; and technology based solutions either in the EVSE or in the OEM telematics that can move the charging load off-peak. I realize that you have ruled out either TOU or CPP rates in the near term as not being cost-effective and feasible, but agree with you that you should continue to monitor the impacts of EV loads on the system regarding rate design techniques. Therefore, you and all the stakeholders should remain focused on these critical costs of unmanaged charging, and controlling the system peak, as you develop specific programs during this period.

Thirdly, you propose an ongoing stakeholder process that can assist you in monitoring and assessing this plan, market development, and the achievements of the specific programs over this five-year period. You have built up a good foundation with various stakeholders during the CDM plan in the recent past, but the TE space includes a number of new and varied stakeholders such as EV service providers (EVSPs, or the charging station providers who all have different business models), vendors, automobile and bus and truck OEMs (Original Equipment Manufacturers), and down the road commercial fleet operators who wish to convert from diesel fuel to electric vehicles. You are in the most appropriate position to facilitate these discussions, under the guidance and supervision of the Board, as these programs develop.

Fourth, it is important to point out that both in Newfoundland and Labrador and many other North American jurisdictions, that the EV infrastructure market development is still in a nascent stage. Multiple business models are being developed by the third party EVSPs, as well as by utilities in all jurisdictions, and it is too early to conclude which model will be the most successful. The Alliance believes that only a strong utility role can help accelerate the transformation of these infrastructure investments and serve as a catalyst or enabler to allow the overall market to succeed. In this context, both a “make-ready investment approach” and a utility “own and operate” approach can be developed and help to transform this market in parallel fashion, as you rightly point out on p. 15. We agree with your conclusions here and urge you to develop multiple approaches and programs in dealing with market gaps and the EV infrastructure industry and vendors.

Regarding the residential charging portfolio, we like your holistic approach to supplement the federal incentive on vehicle purchase incentives, as well as incentives for the installation of Level 2 charging infrastructure at the residence. Consumer surveys and evidence from other jurisdictions (utilities and EVSPs) indicate that over 80 percent of charging is done at home. In order for both consumers and the electric grid (lower system peak) to benefit from these increased loads, it will be important for you to be engaged strongly with the residential use cases, and understand the changes on consumer behavior over time. We also applaud your requirement that Level 2 chargers eligible for your incentives must be capable of demand response, or flexible load management. We would submit that most all manufacturers of EVSE in North America today have such capabilities built in to both the equipment and the software, and are compliant with an open protocol called Open ADR which minimizes the potential impact of vendor lock-in.

Regarding the commercial EV charging portfolio, we appreciate your focus on customized services to potential business and fleet customers, as well as building upon your successes with the current Business Efficiency Program for demand-side conservation. Utilities in other jurisdictions have learned that these end use cases are sensitive to costs, margins, and TCO (total cost of operation) over the life of the vehicles including the associated charging infrastructure. Accordingly, it makes sense to us that you will approach these applications from customers on an individualized basis with projects that must demonstrate benefits both to the customer and the utility.

Finally, we appreciate that you have included a role for enhanced customer education and research (some jurisdictions called this “education and outreach” or E&O) over the next five years, with a budgeted amount of $12 million overall. It makes sense to us to build upon the successes in the takeCHARGE program focused on conservation programs and savings and expand this program to the TE stakeholder space as well. You rightly point out the importance of engaging with new stakeholders and businesses in accelerating the pace of TE in your service territory, such as automobile dealers, EV owners, EVSP providers. It will also be important to engage in ride-and-drive events (when the end of the Covid-19 pandemic allows such physical events to take place again), trade shows in the Province, and leading by example by engaging with NL Power employees on EV adoption and engagement. Moreover, especially in this era of Covid-19, the role of web portals and educating consumers about the basic of EV adoption and charging infrastructure has become even more important. Accordingly, we think that you have set forth a reasonable and necessary budget and range of activities to carry this out.

In summary, we believe that you have developed a comprehensive and sound Plan for transportation electrification and demand side management on which a solid foundation can be based in the future. We appreciate the opportunity to comment on the Plan, and look forward to continuing to engage with you and others in Newfoundland and Labrador in the months and years ahead to achieve these goals.

Sincerely,

Philip B. Jones

Philip B. Jones, Executive Director
1402 Third Avenue, Suite 1315
Seattle, WA 98101

DRIVE ELECTRIC NL

December 7, 2020

In respect to the Newfoundland Power submission
to the Board of Commissioners of Public Utilities, Newfoundland and Labrador

RE: takeCHARGE Conservation Demand Management and Electrification Plan

To whom it may concern,

Drive Electric NL has reviewed the initiatives to encourage the adoption of electric vehicles as outlined in the proposed takeCHARGE Conservation Demand Management and Electrification Plan.

The initiatives for vehicle purchase rebates, charger installation rebates and EV driver education will greatly aid the adoption of electric vehicles in the province. Similar initiatives in place in other provinces such as Quebec and BC demonstrated tangible improvement in EV ownership, year over year.

The adoption of electric vehicles in Newfoundland and Labrador will enable the province to meet climate change commitments, provide significant cost savings to EV owners, and create new opportunities for eco-tourism.

EV use in the province will also provide a new, permanent domestic market for significant surplus power from Muskrat Falls. The adoption of electric vehicles is by far the best long-term solution for rate mitigation. Drive Electric NL advocates for the aggressive adoption of EVs in Newfoundland and Labrador to achieve this goal as quickly as possible.

We applaud Newfoundland Power and Newfoundland and Labrador Hydro's efforts to encourage the adoption of EVs in the province.

Jon Seary
Joe Butler
Drive Electric NL

Drive Electric NL is a not-for profit organization, created to educate individuals and businesses in Newfoundland and Labrador on the benefits of EV ownership and related opportunities. As long term electric vehicle owners and business owners, we draw on a wealth of EV knowledge and experience.

P.O. Box 13851, St. John's, NL, Canada A1B 4G7 - 709.895.3560 - jon@driveelectricnl.ca