Time-Varying Pricing Pilot Program Phase 4

Evaluation, Measurement & Verification Report

June 30, 2026

Nova Scotia POWER
An Emera Company

Abbreviations

AMI	Advanced Metering Infrastructure
ANL	Adjusted Net Load
CPP	Critical Peak Pricing
DiD	Difference-in-difference
DDD	Triple difference-in-differences (Eco Shift)
DOM	Domestic Rate Class
DR	Demand Response
EM&V	Evaluation Measurement & Verification
E1	EfficiencyOne
EV	Electric Vehicle
HDD	Heating Degree Days
HRM	Halifax Regional Municipality
kW	Kilowatt
kWh	Kilowatt hour
MAE	Mean Absolute Error
MBE	Mean Bias Error
MoE	Margin of Error
MURB	Multi-unit Residential Building
NHW	Non-Holiday Weekday
NS Power	Nova Scotia Power
NSEB	Nova Scotia Energy Board
RMSE	Root Mean Square Error
SLR	Seasonal Load Ratio
SOR	Standard Offer Rate
TOU	Time-of-Use
TVP	Time-Varying Pricing

Definitions

Adjusted Net Load	The hourly net system requirement (MW) less all wind generation (MW)
Cohorts	Cohorts are numbered based on the Phase they enrolled in the TVP program. For example, Cohort 4 refers to participants recruited in Phase 4 (i.e. the fourth Winter), which started November 2024.
Commercial	Customers on the Small General and General rate class are referred to as Commercial; this applies to methodology and results. Unless specified as Small General or General, Commercial indicates both rate classes.
Consumption / Usage	Describes electricity consumption in terms of energy (kWh).
Control	Customers who did not participate in the pilot and had met the control group selection criteria requirements with the highest similarity to their treatment counterpart.
Demand	Describes the maximum 15-minute electricity consumption in terms of power (kW) calculated at AMI interval data frequency (i.e. every 15 minutes).
Income	Income definitions are aligned with provincial income tax brackets.[1] Low - (Annual Income ≤ $61,000) Medium - ($61,000<Annual Income ≤ $96,000) High – (Annual Income > $96,000)
Load	Describes the average hourly electricity consumption in terms of power (kW).
Peak	The highest rate paid by TVP participants. For Time of Use (TOU), the term "peak periods" refers to the time during which the peak rate is in effect for the TOU Tariff. For Critical Peak Pricing (CPP), the term "peak events" refers to the time during which the peak rate is in effect.
Phase	The evaluation of Phase 1 of the TVP pilot was conducted with participants who signed up for the first Winter of the pilot and included data between November 2021 and March 2022. Phase 2 includes Cohort 1 and Cohort 2 participants and covers data available between April 2022 and March 2023. This year's evaluation, Phase 4, includes Cohort 1, Cohort 2, Cohort 3 and Cohort 4 participants and covers data available between April 2024 and March 2025.
Pilot period	For this report (Phase 4) this is April 2024 – March 2025.
Pre-pilot	The year before the TVP Tariff took effect for the Cohort. This period is November 2020 to October 2021 for Cohort 1 participants, November 2021

[1] Government of Nova Scotia. (n.d.). *Personal income tax rates and indexation*. Retrieved June 10, 2026, from https://www.novascotia.ca/personal-income-tax-rates-and-indexation

	to October 2022 for Cohort 2 participants, November 2022 to October 2023 for Cohort 3 participants and November 2023 to October 2024 for Cohort 4 participants.
Residential	Customers in the Domestic rate class are referred to as Residential; this applies to methodology and results.
Snapback	Defined as load increases during the four-hour period following a Time-of-Use peak period or a Critical Peak Event. The duration of the snapback is proportional to the peak period or event duration. For example: A peak period from 5 – 9 PM has a Snapback period from 9 PM – 1 AM.
Standard Offer Rate	The default rate applicable to a customer for their specific rate class. For example, residential customers by default would be on the Domestic Tariff.
Treatment	A participant in the TVP pilot rates (i.e. TOU, CPP, MURB TOU)
Winter / Non-Winter	Winter: November through March, inclusive Non-Winter: April through October, inclusive. Historically referred to "Summer" in previous TVP EM&V reports.

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Executive Summary

Nova Scotia Power (NS Power, Company) launched the Time-Varying Pricing (TVP) Tariff Pilot on November 1, 2021, with the purpose of encouraging customers to shift load from Winter peak periods to Winter off-peak periods. These tariffs present customers with the option to lower their energy bills if they participate in load shifting. Shifts in load away from peak periods avoids generation, transmission, and distribution capacity investments. Load shifted away from peak periods also creates system savings in the near-term in the form of reduced fuel, purchased power costs, and carbon emissions.

This report marks the fourth annual TVP Report (i.e. Phase 4, April 1, 2024 to March 31, 2025), as such the load and economic impact evaluation pertains to this period. All cohorts are named according to the Phase of the evaluation in which they joined (i.e. Cohort 2 customers joined the pilot during Phase 2).

Since the first report, modifications to the evaluation metrics and the rates themselves have been made with the support of expert consultants and stakeholders. These modifications have refined the evaluation to provide accurate load and billing effects from customers participating in TVP, while creating rates that achieve demand response (DR) targets in a cost-optimized manner. One of these modifications included the transfer of TVP evaluation measurement and verification (EM&V) from consultants to NS Power, Phase 4 marks the first evaluation performed by NS Power.

Residential Time-of-Use (TOU) and Critical Peak Pricing (CPP) participants have expanded their enrolment by a combined 5,148 customers since Phase 3 – this represents an increase of approximately 160%. These Domestic Tariffs continue to demonstrate on-peak load reduction effect per customer similar to previous Phases (TOU = 0.16 kW or 7.6%, CPP = 0.69 kW or 27%). These effects are similar during periods of low wind and high system load (i.e. highest adjusted net load (ANL) hours).

Since Phase 3, Commercial TOU and CPP participants have expanded their enrolment by a combined 43 customers – an increase of approximately 66%. This increase in sample size combined with improved regression methodologies has, for the first time, demonstrated statistically significant on-peak load reduction effect per customer (TOU = 0.80 kW or 7.5%, CPP = 6.3 kW or 9.6%). For CPP, these effects are not observed consistently across all event calls but are observed during the highest ANL hours, whereas for TOU the effect during top ANL hours is statistically insignificant.

For the first time, the ten customers on the Multi-unit Residential Building (MURB) TOU Tariff were evaluated. Results indicate a small, but statistically significant, load shift during evening peak periods (0.54 kW, approximately 2.1%). During the morning period and during the highest ANL hours, MURB TOU customers indicate potential load reductions; however, these results are statistically insignificant. Notably, no change in monthly demand was observed in MURB TOU participants, despite the removal of the demand charge.

As the TVP Pilot evolves and scales, this report not only serves as a diagnostic tool for program evaluation, but it also aids in determining the next steps for TVP DR in Nova Scotia.

Tariffs

Both TOU and CPP are available in the Domestic, Small General, and General rate classes, whereas MURB TOU is available to MURBs in the General rate class. A summary of the TVP Tariffs is provided in Attachment I: Riders and Tariff Structure.

Domestic, Small General, and General TOU has two four-hour peak periods occurring on all non-holiday weekdays, 7–11 AM and 5–9 PM, November through March (Winter); all other hours during the Winter period are considered off-peak. During Winter off-peak periods, customers are charged the same as the standard offer rate (SOR), while during on-peak periods, customers are charged twice the off-peak rate. From April to October (non-Winter), the rate is approximately 30% lower relative to the SOR for the entire season.

MURB TOU has two four-hour peak periods (7–11 AM, 5–9 PM) with a mid-peak (11 AM–5 PM) occurring seven days per week during the Winter season. During non-Winter there is one peak period per day (7 AM – 9PM) with all other hours as off-peak. Unlike the other TOU rates, holidays and non-holidays have the same rate structure. Unlike the General SOR, the MURB TOU Tariff does not have a demand charge. The mid-peak Winter rate is equal to the SOR first energy block.[2] During Winter, the on-peak rate is twice that of the SOR rate and the off-peak is approximately 15% lower relative to the SOR rate. During non-Winter, the on-peak and off-peak rates are 5% and 20% lower, respectively, as compared to the SOR first energy block.

CPP has up to 18 four-hour events per Winter season. Events are scheduled by the System Operator based on the day-ahead system load forecast and dispatch schedule. Customers must be notified by 4 PM the day before the event. Customers are reminded within one hour of the event starting and once it is completed. Events can be called up to three times per week (Monday through Sunday), at any time between 6 AM and 11 PM, and may include up to three weekend events per TVP Season. Peak pricing for CPP is 10 times the SOR price, and off-peak pricing is approximately 16% lower than the SOR rate for each rate class.

Residential Findings

In total, 5,616 TOU and 2,642 CPP residential customers participated in the TVP program in Phase 4. Of these, 4,938 TOU and 2,310 CPP customers were included in the regression when counting only those who meet the criteria defined by the methodology; as described in . Consistent with Phase 3, TVP Pilot participants continued to achieve significant electricity load reductions during peak periods (for TOU) and events (for CPP), as summarized in Table 1.

Table 1: Summary of Peak Load Reductions by Residential TVP Tariff

TVP Tariff	Absolute Load Reduction (kW)		Relative Load Reduction (%)	
	Morning Peak	Evening Peak	Morning Peak	Evening Peak
Residential TOU	0.15 kW	0.17 kW	7.4%	7.9%
Residential CPP	0.61 kW	0.77 kW	24.6%	28.5%
Statistical Significance	✓	✓	✓	✓

[2] The General SOR Energy Charge has two blocks: one for the first 200 kWh per month per kW of maximum demand and a lower rate for all additional kWh.

Residential TOU participants reduced load during peak periods (0.16 kW / 7.6%) with minimal snapback (0.014 kW during evenings only) while also reducing overall annual energy (300 kWh per year), resulting in an average annual electricity bill reduction ($110 / 5.5%). This average load reduction during peak hours in Phase 4 is consistent with that observed in Phase 3 (0.15 kW). Significant enhancements to load reduction (+0.40 kW) occurred where technology (i.e. Eco Shift + smart device) were present. Notably, load impact during the highest 88 ANL hours were consistent with average peak periods (0.17 kW). All heating classifications demonstrated load reduction; however, those with steady electric space heating achieved the highest average load reduction of 0.19 kW during peak hours, whereas participants with steady non-electric space heating systems experienced the lowest load reduction of approximately 0.08 kW. Participants who electrified their space heating with TOU provided a compelling case for electrification by achieving statistically significant load reduction (0.11 kW) during peak periods with no statistically significant change in overall annual energy consumption (27.7 ± 37 kWh per year) while still saving on their annual electricity bill ($153 per year) in addition to any fuel savings from non-electric heating sources they may have reduced.

Residential CPP participants reduced load during peak periods (0.69 kW / 27%) with a statistically significant overall snapback (0.060 kW). Participants reduced overall annual energy (355 kWh per year), resulting in an average annual electricity bill reduction ($208 / 8.6%). This average load reduction during peak hours in Phase 4 (0.61 ± 0.03 kW morning / 0.77 ± 0.03 kW evening) is less than that observed in Phase 3 (0.768 ± 0.222 morning / 0.943 ± 0.439 kW evening); however, the differences are within the margin of error. Significant enhancements to load reduction (0.46 kW) occurred where technology (i.e. Eco Shift + smart devices) were present. Notably, load impact during the highest 88 ANL hours that coincided with CPP events (0.80 kW) were higher than during average peak periods. All heating classifications demonstrated load reduction; however, those with steady electric space heating achieved the highest average load reduction of 0.83 kW during peak hours, whereas participants with steady non-electric space heating systems experienced the lowest load reduction of approximately 0.24 kW. Participants who electrified their space heating with CPP provided a compelling case for electrification due to achieving statistically significant load reduction (0.75 kW) during peak periods with marginal overall annual energy increase (945 ± 211 kWh per year). Although electrified participants did not experience statistically significant change (i.e. increase or decrease) in electricity bill, it does not account for any additional fuel savings from non-electric heating sources they may have reduced.

Commercial Findings

The commercial TVP Tariffs attracted more businesses, with Phase 4 enrolment (108 businesses) higher compared to Phase 3 (65 businesses). While "small sample size and the wide variety of energy consumption profiles prevented obtaining conclusive impact evaluation results"[3] in Phase 3, the larger sample and improved regression analysis in Phase 4 enable a more robust assessment of the load and economic impacts of TVP commercial tariffs. Commercial TVP pilot participants achieved significant electricity load reductions during peak periods (for TOU) and events (for CPP) in Phase 4 (Table 2).

[3] M11823 – TVP Pilot Program — 2023/24 (Year Three) Evaluation Report, Appendix A, page 51. July 31, 2024.

Table 2: Summary of Load Reductions by Commercial TVP Tariff

TVP Tariff	Absolute Load Reduction (kW)		Relative Load Reduction (%)	
	Morning Peak	Evening Peak	Morning Peak	Evening Peak
Commercial TOU	0.7 kW	0.9 kW	6.4%	8.6%
Commercial CPP	7.9 kW	5.1 kW	11.4%	7.9%
Statistical Significance	✓	✓	✓	✓

Commercial TOU Participants reduced load during peak periods (0.80 kW / 7.5%) with a statistically significant evening snapback (0.90 kW). However, the overall snapback effect of 0.11 kW for TOU participants was not statistically significant due to a load reduction during the morning snapback period (0.51 kW). Notably, largest overall reductions occurred during the evening peak period in February 2025, when the average outdoor temperature was on average −3 °C. Overall, commercial TOU participants experienced an increase in daily electricity usage of 15.4 kWh/day. When separated by rate class, Small General customers exhibit a load increase during peak periods (0.22 kW) relative to the General rate class that demonstrate a load reduction (2.6 kW). These results suggest that commercial TOU participants under General Tariff are more responsive to price signals, while those under Small General Tariff show counterproductive responses. During the highest ANL hours that coincide with TOU peak periods, participants did not exhibit statistically significant load reduction.

Commercial CPP Participants reduced load during peak periods (6.3 kW / 9.6%) with a statistically insignificant overall snapback. Notably, the CPP participants exhibited a statistically significant snapback effect (6.9 kW) on days when both morning and evening CPP events occurred. The CPP participants achieved the largest overall reductions during the evening event in December 2024, when the average outdoor temperature was on average −8 °C. Overall, commercial CPP participants experienced a significant reduction in daily electricity usage of 65 kWh/day during CPP event days. When separated by rate class, Small General customers exhibit no statistically significant changes in load during peak periods compared to the General rate class that demonstrate a load reduction (9.7 kW). These results suggest that commercial CPP participants under General Tariff are more responsive to price signals, while those under Small General Tariff show statistically insignificant responses. During the highest ANL hours that coincide with CPP peak periods, participants achieved higher-than average load reductions.

MURB TOU Findings

Phase 4 marks the first load and economic impacts evaluation of the MURB TOU Pilot Tariff. Ten MURBs were recruited and are enrolled in the MURB TOU Tariff. For the MURB TOU Tariff, this Phase 4 evaluation includes the Winter period from November 2024 to March 2025.

MURB TOU participants achieved an overall load reduction of approximately 0.48 kW during peak periods; however, only the reduction during evening peak hours was statistically significant (Table 3). MURB TOU participants demonstrated overall load reductions during the Winter period, except in March, when they exhibited a significant increase in load.

Table 3: Summary of Load Reductions from MURB TOU Tariff

TVP Tariff	Absolute Load Reduction (kW)		Relative Load Reduction (%)	
	Morning Peak	Evening Peak	Morning Peak	Evening Peak
MURB TOU	0.44 kW	0.54 kW	1.8%	2.1%
Statistical Significance	X	✓	X	✓
Note: Throughout this report, statistically significant results will be displayed in tables with black font, whereas statistically insignificant results will be displayed in grey font.				

MURB TOU participants demonstrated an overall negative snapback effect (0.92 kW), indicating reduced electricity use during snapback periods. On average, participants reduced load by 1.2 kW during the morning snapback period and no statistically significant snapback during the evening snapback period. MURB TOU participants demonstrated mixed results across the highest ANL hours. These reductions were not statistically different from the average load reductions observed during ANL hours that coincided with TOU peak periods. Statistically significant reductions were only observed during the top 50 and top 88 highest ANL hours.

Unlike other tariffs in the General rate class, the MURB TOU Tariff offers an electricity rate without a demand charge. To understand the demand impact, the effect MURB TOU Tariff on demand was evaluated. Findings revealed that MURB TOU participants saw no statistically significant changes in monthly demand, although statistically significant 15-minute demand decrease occurred during morning snapback period and pre-evening snapback periods it did not impact monthly demand. Additionally, MURB TOU participants demonstrated statistically insignificant changes in daily electricity usage during the Winter overall and during individual Winter months. Notably, many of the findings from MURB TOU impact analysis are not conclusive due to the small sample size.

Introduction

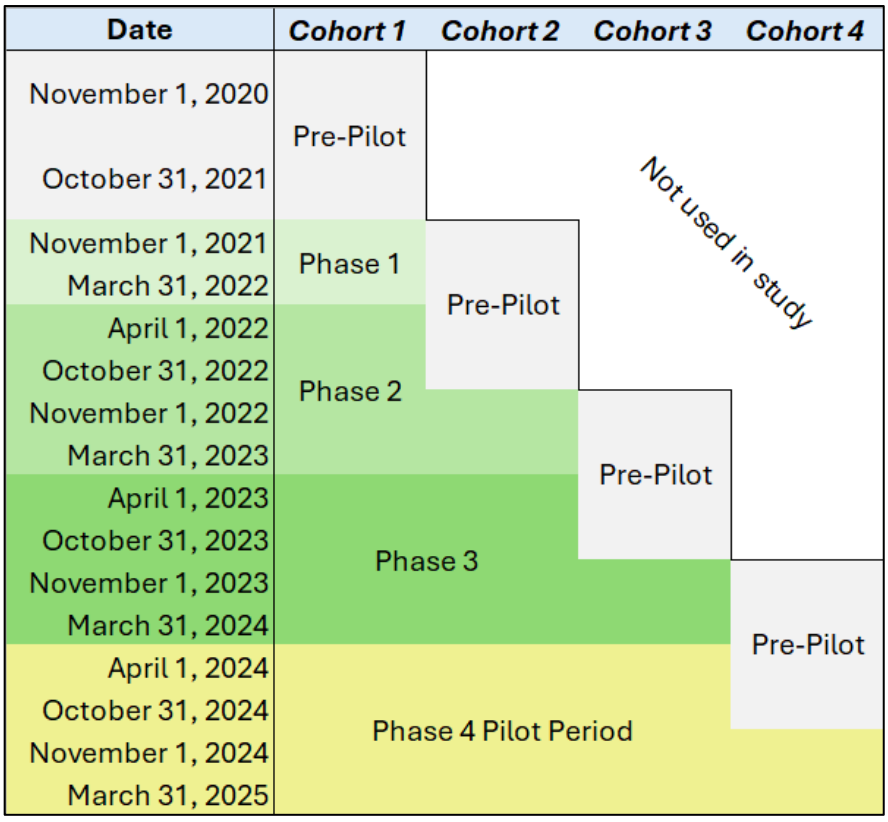
Time-Varying Pricing (TVP) is a scalable customer-focused demand response (DR) program. In Nova Scotia, the TVP pilot has grown significantly since it began in November 2021. Since its inception, the TVP pilot has offered two tariffs, Time-of-Use (TOU) and Critical Peak Pricing (CPP), within three separate rate classes (Domestic, Small General and General). The objective of these rates is to provide customers with rate choice that can enable them to save on their electricity bill while shifting demand from peak periods. By promoting load shifting, the program aims to reduce, in the near term, fuel and purchased power costs, and over the longer-term reduce costs in the form of avoided generation, transmission, and distribution infrastructure capital costs.

This report and its analytical process serve as a method for quantifying the load and billing impacts from TVP. Through stakeholder collaboration, the evaluation methods, the rates, and the TVP Tariff constructs have been modified iteratively. New in Phase 4 is the multi-unit residential building (MURB) TOU Pilot Tariff, which was launched on November 1, 2024. This is the first new Tariff since the inception of the TVP pilot program. This Tariff, along with the six originals, are evaluated as part of this year's Evaluation, Measurement, and Verification (EM&V) report (i.e. TVP Phase 4 EM&V).

Evaluation Scope

This evaluation pilot period (i.e. Phase 4) analyzes advanced metering infrastructure (AMI) data from November 1, 2020 – March 31, 2025. Each Phase, the pilot period shifts by 1-year; however, the pre-pilot period remains static for each cohort, as illustrated in Figure 1.

Figure 1: Phase 4 Experimental Design Timeline



The first year a cohort enters the TVP pilot (e.g. Cohort 2 in Phase 2), the evaluation for this cohort was limited to the Winter period (i.e. November to March). Subsequent evaluations for all cohorts include a full year (i.e. April to March).

Evaluation metrics are separated into two impact categories, "Load & Usage" and "Economic". Refer to Table 4 for a summary of each metric included in the Phase 4 report.

Table 4: Impact Evaluation Metric Summary

Category	Metric	TOU, CPP, MURB TOU (all rate classes unless specified)
Load & Usage Impact	**Change in load during peak periods (kW)**	• Change in load (kW) during peak, and overall impact during Winter and non-Winter. Mid-peak hours included for MURB TOU. • Change in load during peak by region (Halifax area vs. rest of Nova Scotia). • Change in load by month (TOU rates only). • Change in load by space heating classification (Residential rates only). • Additional change in load from Eco Shift program (Residential rates only). • Change in load by income classification (Residential rates only).
	Snapback (kW)	• Change in hourly average load (kW) over 4 hours immediately after peak hours.
	Change in load during highest ANL hours (kW)	• Change in load during the highest adjusted net load (ANL) hours based on the highest 20, 50, and 88 ANL hours during the year, including analysis of coincident tariff peak and highest ANL hours.
	Change in average usage levels (kWh)	• Change in the average daily usage levels (kWh/day) and relative change in daily electricity usage (%) during Winter and non-Winter.
	Change in Demand (kW), MURB TOU only	• Change in maximum 15-minute load with respect to peak periods, pre-peak and post-peak (i.e. Snapback Period). • Change in maximum 15-minute load with respect to month.
Economic Impact	**Change in electricity bills**	• Change in daily electricity bill ($) during Winter, non-Winter, and annual average.
	Price Elasticity	• Daily and inter-period substitution price elasticity (percent (%) change in load per one percent (%) change in price).

Participation

The TVP pilot program has increased enrolment year over year with a total of 8,376 participants at the end of Phase 4. Refer to Table 5 and Table 6 for participation summaries.

Table 5: TVP Participation on March 31 by Phase and Tariff

Phase	DOM TOU	SMG TOU	GEN TOU	DOM CPP	SMG CPP	GEN CPP	MURB TOU	Total
Phase 1	676	24		284	8		0	**992**
Phase 2	891	17		373	2		0	**1,283**
Phase 3	2,241	37	19	922	3	6	0	**3,228**
Phase 4	5,616	37	18	2,642	17	36	10	**8,376**

The average customer retention rate per TVP Tariff ranges from 87% (Domestic TOU) to 100% (MURB TOU), refer to Table 6 for additional details.

Table 6: Participation Summary and Retention Results

TVP Tariff	A Enrolled prior to beginning of Phase 4 Winter (October 31, 2024)	B Enrolled during Phase 4 Winter (November 1, 2024 to March 31, 2025)	C Withdrew mid Phase 4 Winter (November 1, 2024 to March 31, 2025)	D Remained enrolled at end of Phase 4 Winter (March 31, 2025)	$1-\left(\frac{C}{A+B}\right)$ Percentage of Enrolled Participants Who Completed Phase 4
Domestic TOU	2,174	4,271	829	5,616	87%
Domestic CPP	885	2,023	266	2,642	91%
Small General TOU	36	5	4	37	90%
Small General CPP	3	16	2	17	89%
General CPP	19	0	1	18	95%
General TOU	6	32	2	36	95%
MURB TOU	10	0	0	10	100%

1 Methodology

The methodology is primarily composed of two components: control group selection and regression modelling.

Control group selection includes matching treatment customers with control customers based on a similar location (i.e. neighbourhood), space heating type (e.g. electrified), participation in EfficiencyOne's (E1) Eco Shift program, while balancing for effects from other E1 programs such as Green Heat, Home Energy Assessment, and Efficient Product Installation. While considering these non-load metrics, each treatment customer is matched to a control customer with the most similar average and peak load profiles during the pre-pilot period by means of a 'Similarity Metric,' which is defined by a Euclidean distance calculation.

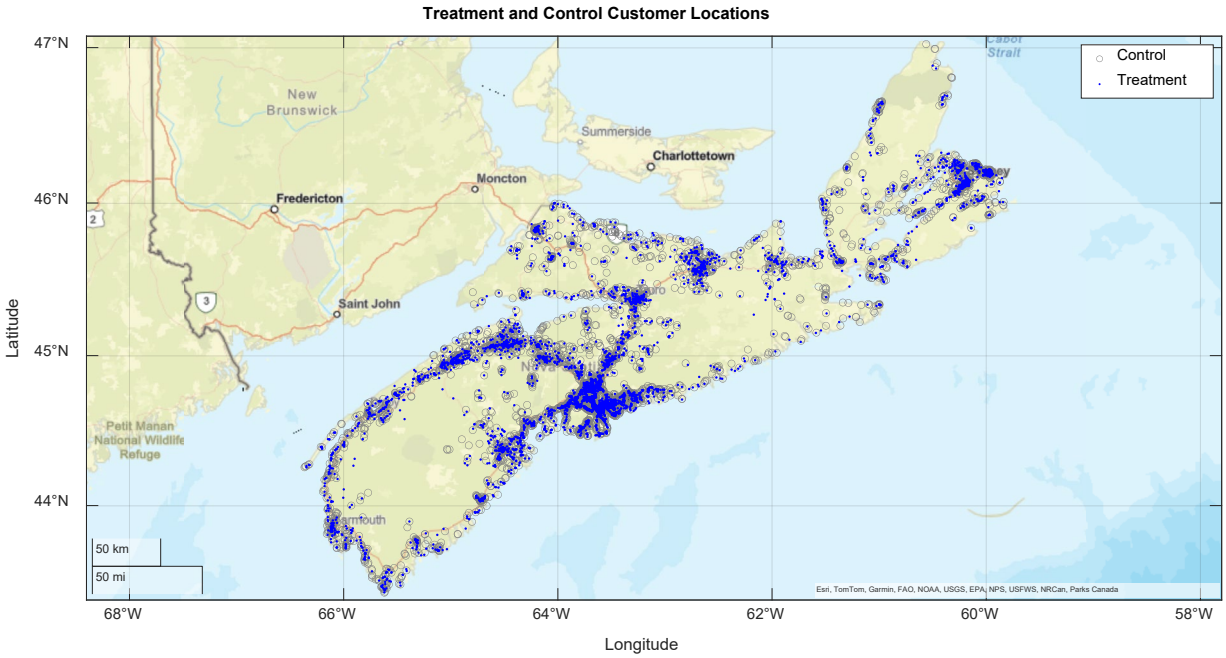
The regression models in this EM&V use both a fixed and mixed-effects regression model that primarily relies on a difference-in-difference (DiD) model, and where necessary, a triple difference (DDD) model is utilized. Generally, the regression model includes variables to account for which customers are control and treatment, TVP price signals, and temperature using heating degree days (HDD). For commercial TOU and CPP tariffs, a semi-difference-in-differences (semi-DiD) approach is used due to not establishing a viable control group.

For additional details regarding the methodology and equations used, refer to Attachment III: Methodology. For how these methodologies have progressed since the start of TVP at Nova Scotia Power, refer to Attachment IV: Historical Methodological Changes.

2 Control Group Selection

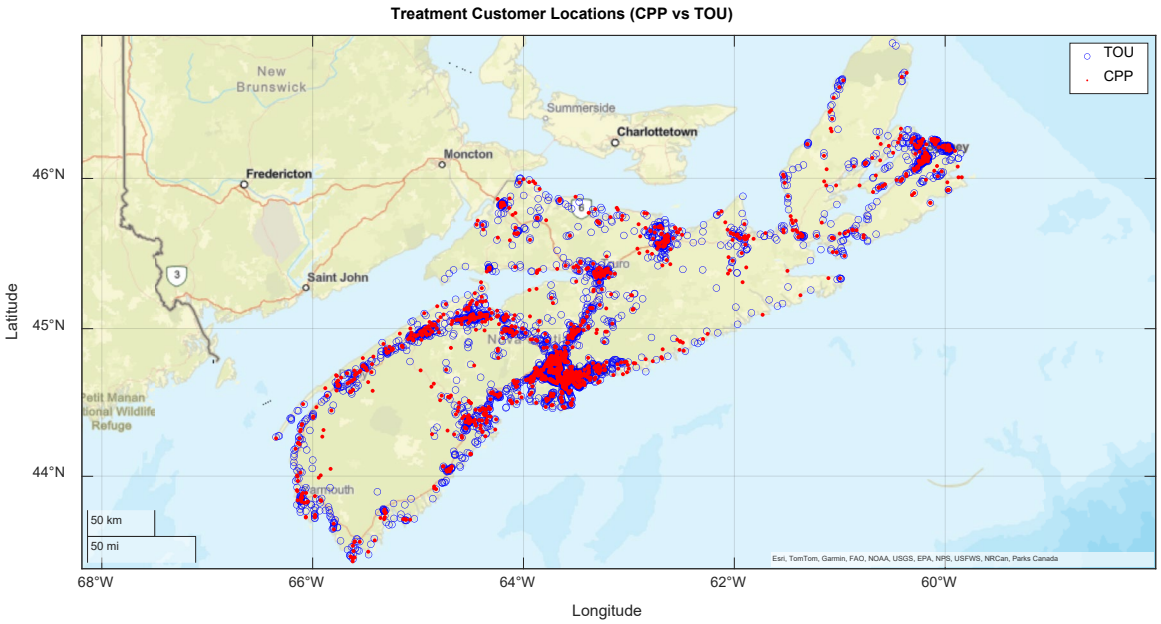
The control group selection methodology uses 1-hour average and 15-minute peak load data to determine the best 1:1 control match by four neighbourhoods. If treatment customers are distributed throughout the province proportional to the population, control customers should follow a similar distribution. To confirm this assumption, a geographic visual of Nova Scotia demonstrates both Treatment and Control customers are distributed similarly to each other; refer to Figure 2.

Figure 2: Geographic Distribution of Treatment and Control Customers from all Rate Classes



Although it is not a pre-requisite that CPP and TOU customers be similarly distributed throughout Nova Scotia, it is a benefit which ensures comparison between the two programs are not skewed due to any potential geographic differences. The distribution of both TOU and CPP treatment customers is presented in Figure 3.

Figure 3: Geographic Distribution of TOU and CPP Treatment Customers (All Rate Classes)



As shown in Figure 2 and Figure 3, the distribution of Treatment and Control groups for both TOU and CPP customers is observably distributed in alignment with the Nova Scotia population.

2.1 Residential TOU & CPP

To best evaluate load and billing effects of the TVP pilot, it is important to have a control group with similar load characteristics to that of the treatment group. The control group selection load profile match is presented for TOU and CPP in Figure 4 and Figure 5, respectively, with results indicating greater than a 96% match accuracy for both average and maximum loads as defined by the methodology in equation (4).

Figure 4: Residential TOU Pre-Pilot Control & Treatment Load Profile Comparison

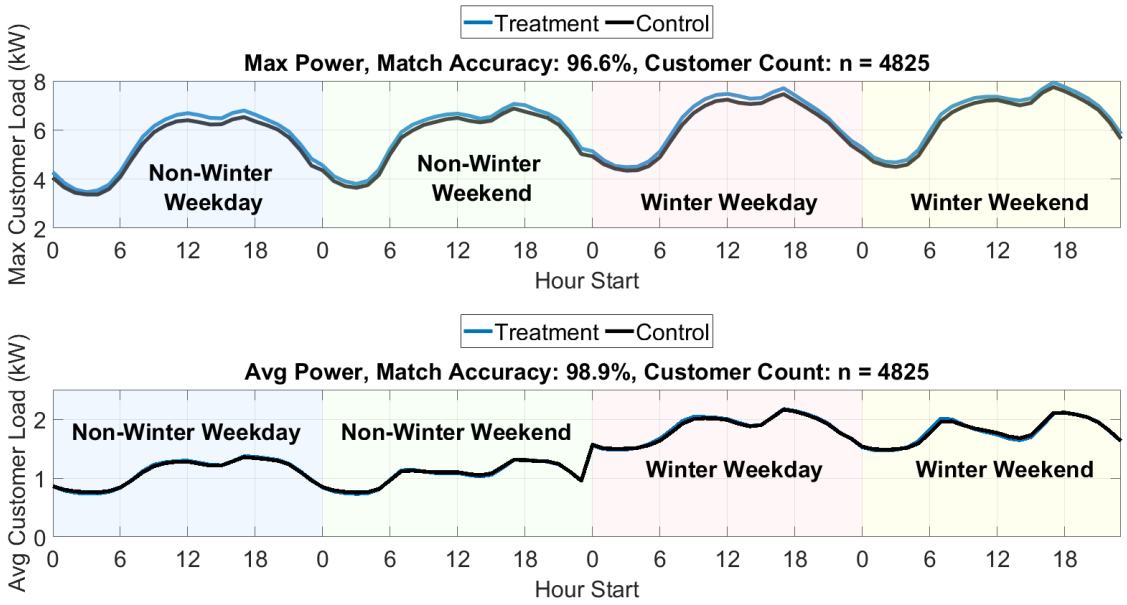
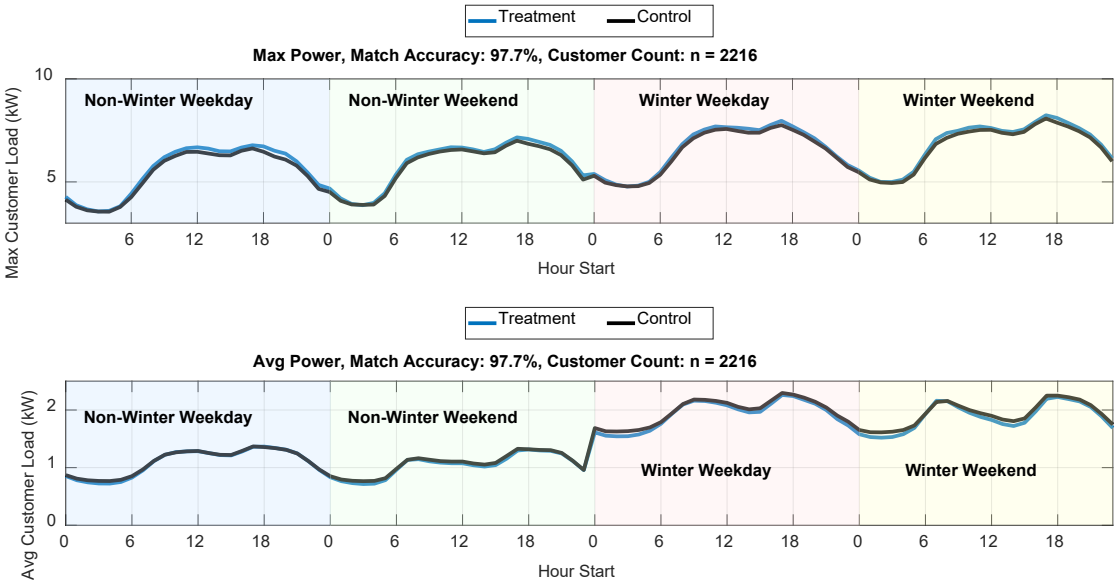


Figure 5: Residential CPP Pre-Pilot Control & Treatment Load Profile Comparison



The match accuracies compare load curves from both control and treatment. Data used for match accuracy are defined by the start hour of day (0 to 23), season (non-Winter or Winter), day type (Weekday or Weekend) and load type (average or maximum). This provides a total of 192 unique data points (hour × season × day type × load type) used to find an individual 1:1 control treatment match. As such, these match accuracies indicate a highly similar TOU and CPP control groups for their respective treatment groups. Notably, samples sizes are less than that provided in Table 5, this is a result of cleaning processes summarized in Table 68.

In addition to ensuring Pre-Pilot treatment and control loads are similar, it is valuable to analyze that baseline characteristics which influence diversity between treatment and control such as income, residents per household, year built, living space and dwelling style are compared. Unlike average and peak loads which are integral to control group selection, these baseline characteristics are not accounted for directly during control group selection. Refer to Attachment VI: Control Group Selection Non-Load Variables for data on baselines load characteristics for control, treatment, and the Nova Scotia population.

In summary, the analysis of baseline characteristics (i.e. income, residents per household, year built, and housing style) demonstrated that the control and treatment groups exhibit similar distributions to each other and to the population. However, living space is one metric that is similar between control and treatment groups but is approximately 13% larger (200 ft^2) than the population average. The difference in dwelling size combined with increased electric space heating penetration in TVP (71%) relative to the residential population (≤%60)[4] are expected to be main driving factors[5] as to why TVP customers consume approximately 2,450 kWh, or 24%, more than the average residential SOR customer (refer to Table 7).

Table 7: Average Residential Annual Energy Consumption (SOR & TVP)[6]

Group	Energy (kWh)
SOR	10,225
TVP	12,678

2.1.1 Eco Shift

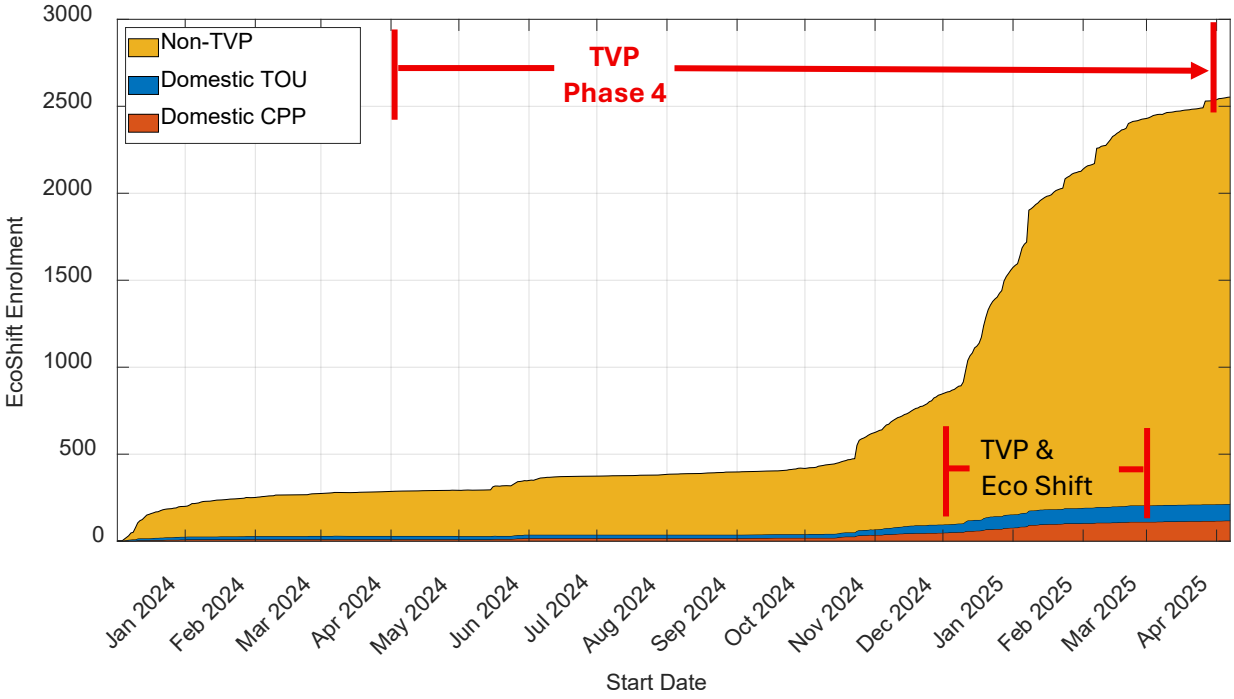
New to the TVP evaluation this year, is the analysis of E1's Eco Shift program combined with TVP customers. As of the end of TVP Phase 4, enrolment 2,500 participants were enrolled in E1's Eco Shift program, 209 of which were also TVP participants. A timeline of Eco Shift and TVP participants enrolled in the program during Phase 4 of the TVP evaluation is visualized in Figure 6.

[4] M12349 – 2025 Load Forecast Report, Figure 20, page 24. June 27, 2025.

[5] Statistics Canada. (2013). *Households and the environment: Energy use (2011)*. Catalogue no. 11-526-S. Government of Canada. https://www150.statcan.gc.ca/n1/en/pub/11-526-s/11-526-s2013002-eng.pdf

[6] Excluding net metering, seasonal and charitable rates within the domestic rate class.

Figure 6: Eco Shift Enrolment Timeline (TVP Phase 4 Period)



Additional analysis on the device type indicated that a majority of customers on both TVP and Eco Shift only had smart thermostats installed (87.6%, n=183), where those with EVs only represent (9.1%, n=19), and customers with both smart thermostats and EVs (3.4%, n=7). Notably, Eco Shift participants with smart thermostats often had multiple smart thermostats.

With respect to control group selection, all 209 identified TVP Eco Shift participants were matched with a control customer on the SOR (i.e. non-TVP) who did not participate in the Eco Shift program.

2.1.2 E1 Program Balancing

As discussed in methodology, E1 program participation is accounted for in control group selection, refer to Attachment III: Methodology. The results indicate that E1 program participation across all sub-groups (e.g. Cohort, Heating Type) has been balanced, achieving an overall balance accuracy of 99.1% defined by equation (3).

2.2 Commercial TOU & CPP

The same methodological approach as used with residential control group (with exception to Neighbourhood Criteria, Heating Classification, and Eco Shift) was used in attempting to select a control group for Small General and General (i.e. Commercial) TOU and CPP rates. The load profiles comparison of the potential control group is provided for Small General (TOU and CPP) and General (TOU and CPP), respectively, in Figure 7, Figure 8, Figure 9, and Figure 10. The results indicate poor matching for control selection as reflected in the low match accuracy, suggesting these control

groups are unsuitable. This result is similar to previous Phases, as such, the regression analysis for these TVP Tariffs will be within-subject (i.e. semi-DiD).

Samples sizes shown in Figure 7 through Figure 10 are less than that provided in Table 5, this is a result of cleaning processes summarized in Table 68.

Figure 7: Small General TOU Pre-Pilot Control & Treatment Load Profile Comparison

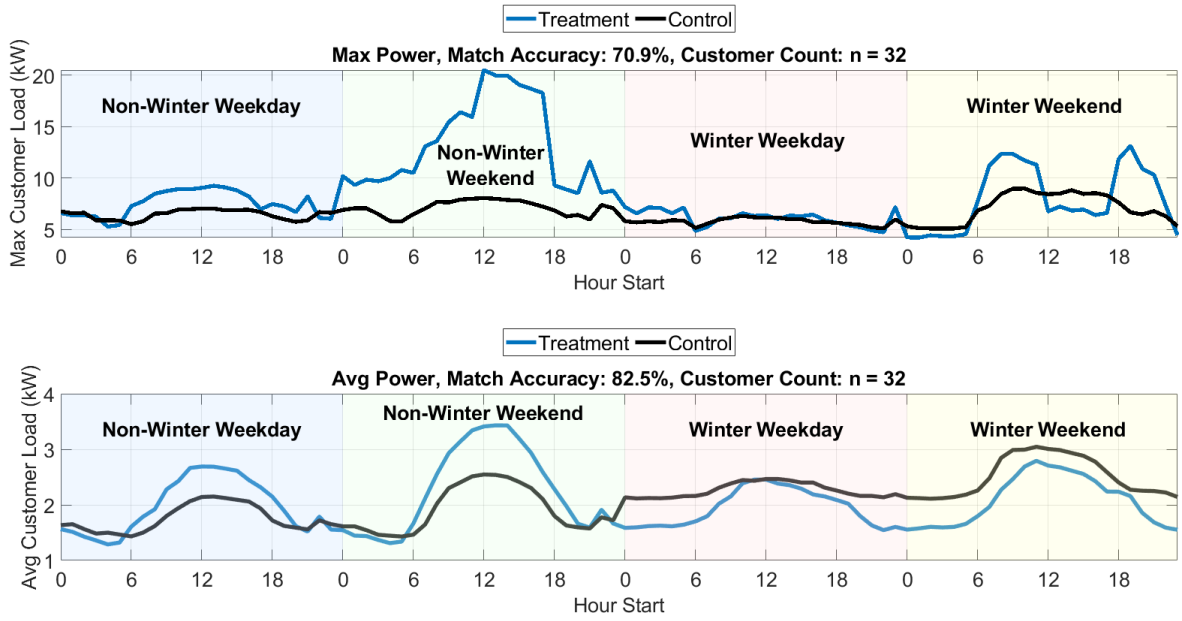


Figure 8: Small General CPP Pre-Pilot Control & Treatment Load Profile Comparison

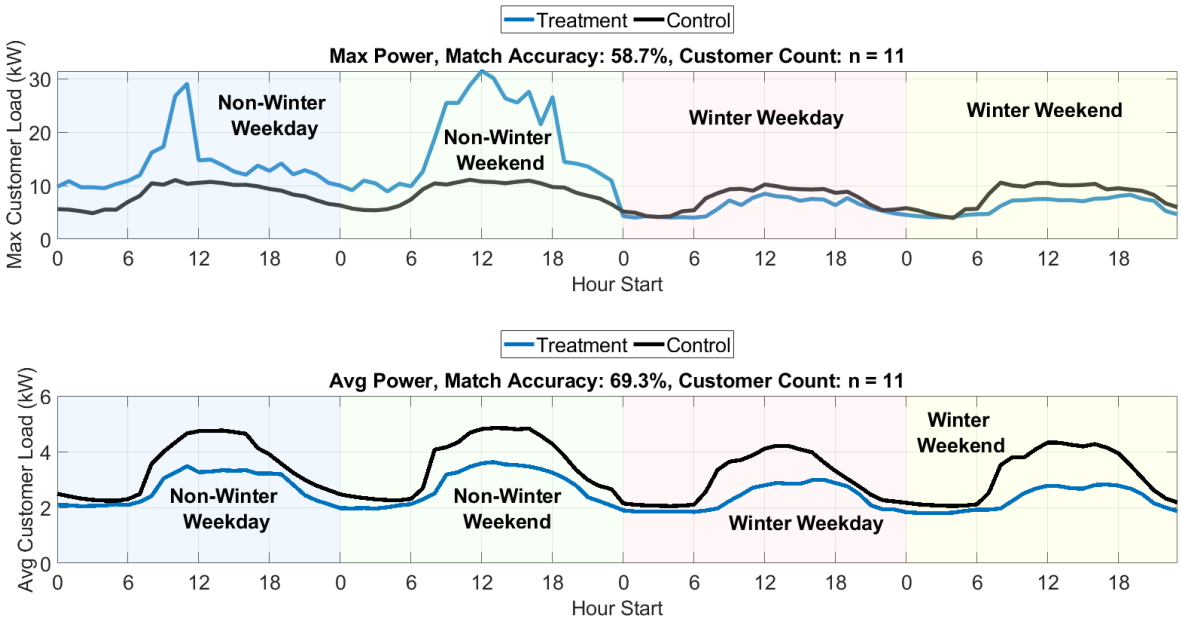


Figure 9: General TOU Pre-Pilot Control & Treatment Load Profile Comparison

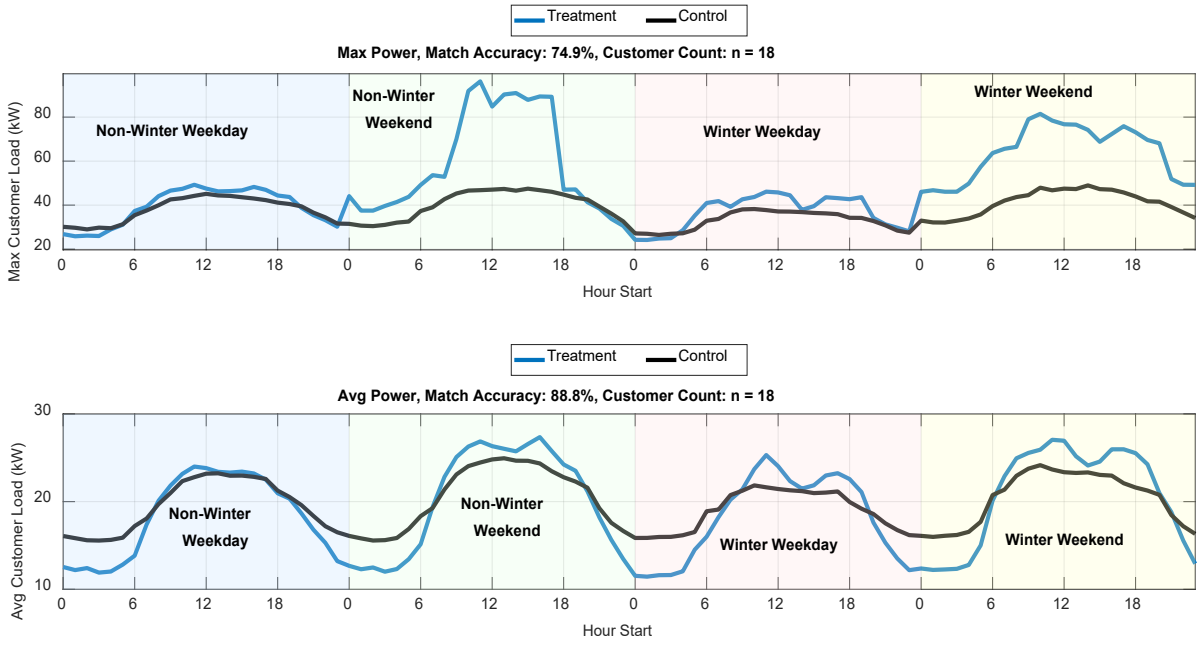
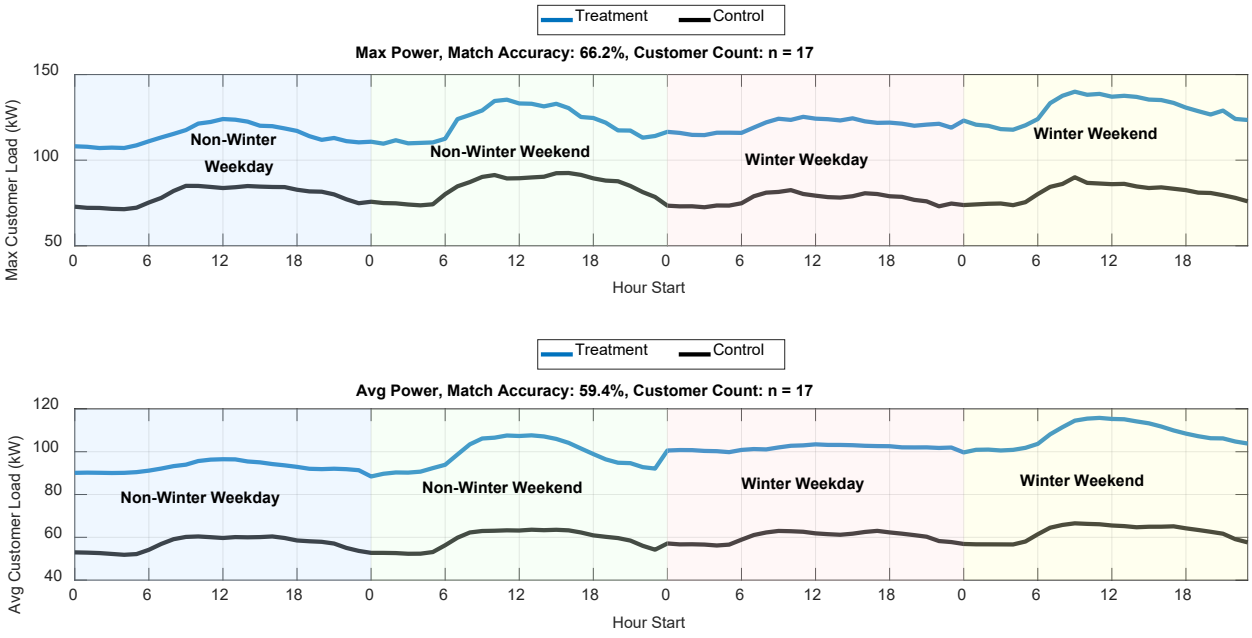


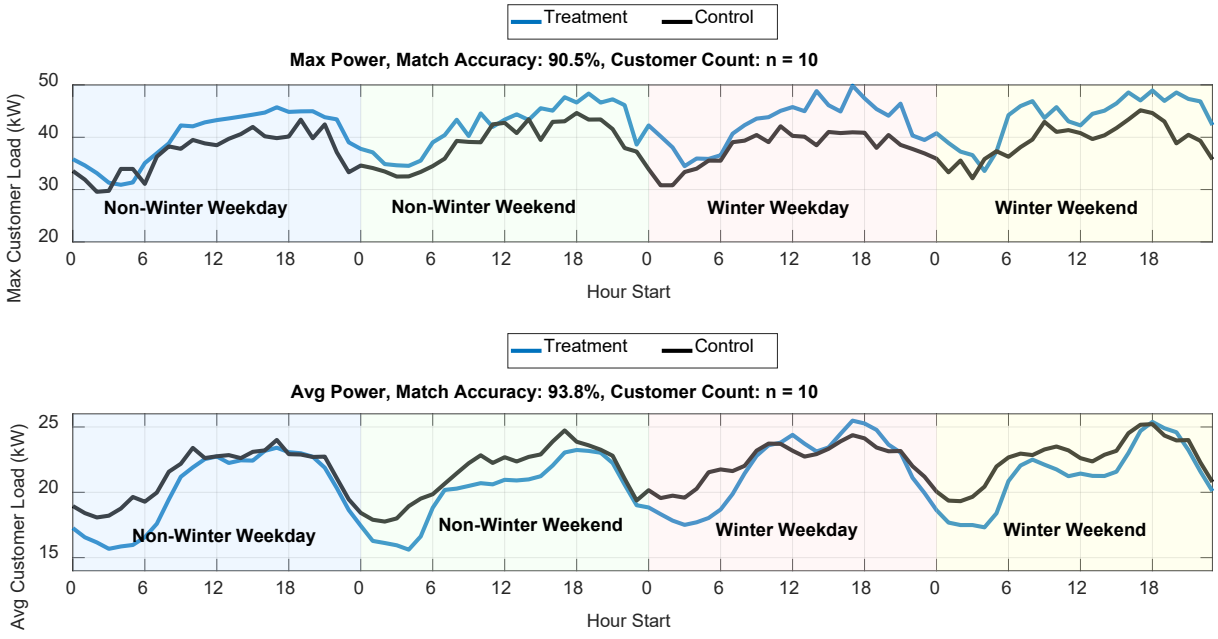
Figure 10: General CPP Pre-Pilot Control & Treatment Load Profile Comparison



2.3 MURB TOU

For MURB TOU, the control group selection model was successful (Match Accuracy ≥ 90%) in selecting a 1:1 control for the ten MURB TOU treatment customers, refer to load profiles below in Figure 11.

Figure 11: MURB TOU Pre-Pilot Control & Treatment Load Profile Comparison



The control group selection load comparison results for MURB TOU indicate a good match accuracy and thus a control group will be used for this subset of commercial customers.

2.4 CPP Reference Days

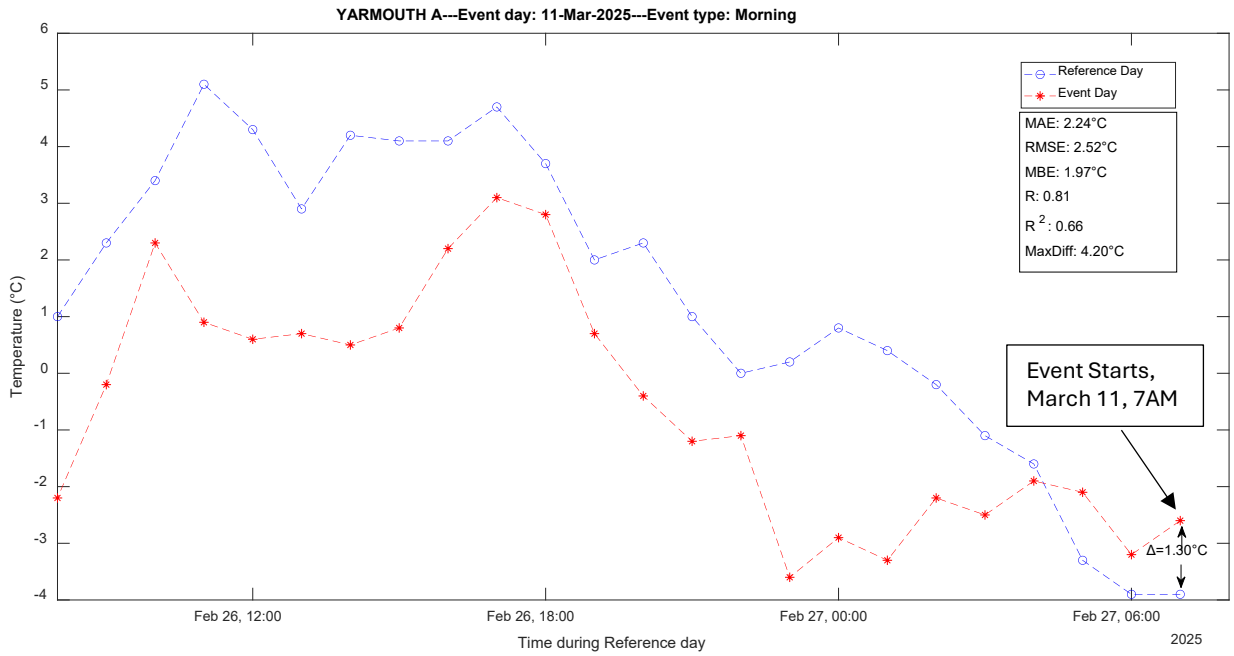
The CPP reference days were selected for Phase 4 are summarized in Table 8.

Table 8: Phase 4 CPP Event Reference Day Results

Event Day	HALIFAX AIRPORT	KENTVILLE CDA CS	NAPPAN AUTO	SHEARWATER RCS	SYDNEY AIRPORT	TRACADIE	WESTERN HEAD	YARMOUTH AIRPORT
12/4/2024	12/3/2024	12/3/2024	12/3/2024	12/3/2024	12/3/2024	12/3/2024	12/3/2024	12/3/2024
12/15/2024	12/14/2024	12/14/2024	12/14/2024	12/14/2024	12/14/2024	12/14/2024	12/14/2024	12/14/2024
12/20/2024	12/27/2024	1/3/2025	12/2/2024	12/2/2024	1/3/2025	12/2/2024	1/3/2025	12/2/2024
12/22/2024	12/7/2024	12/7/2024	12/7/2024	12/7/2024	12/7/2024	1/5/2025	1/5/2025	1/5/2025
12/23/2024	1/6/2025	1/6/2025	1/6/2025	1/6/2025	12/21/2024	1/6/2025	1/6/2025	1/6/2025
1/21/2025	1/23/2025	1/29/2025	1/29/2025	1/30/2025	1/23/2025	1/29/2025	1/16/2025	1/16/2025
1/22/2025	1/23/2025	2/11/2025	2/11/2025	1/23/2025	1/23/2025	1/23/2025	1/16/2025	2/11/2025
2/2/2025	2/15/2025	2/9/2025	2/9/2025	2/15/2025	1/25/2025	2/16/2025	2/15/2025	1/25/2025
2/5/2025	1/30/2025	1/30/2025	1/30/2025	1/30/2025	1/30/2025	1/30/2025	2/18/2025	2/18/2025
2/6/2025	1/23/2025	1/23/2025	1/23/2025	1/23/2025	1/23/2025	1/23/2025	1/23/2025	2/19/2025
3/4/2025	2/13/2025	2/13/2025	2/18/2025	2/13/2025	2/13/2025	2/13/2025	2/19/2025	2/19/2025
3/10/2025	2/21/2025	3/14/2025	3/14/2025	3/14/2025	3/14/2025	3/14/2025	2/21/2025	2/24/2025
3/11/2025	2/27/2025	3/13/2025	3/13/2025	2/27/2025	2/20/2025	2/20/2025	2/27/2025	2/27/2025

For example, the CPP event day on December 4, 2024, has the same reference day for all eight weather stations (December 3, 2024). Although each weather station is independently assessed for the most similar temperature data, the analysis indicates December 3, 2024, was the most similar temperature day to the event day for all weather stations. On the contrary, the event on March 11, 2025, has different reference days for some weather stations. For example, for the March 11 event, customers nearest to the Sydney A weather station, the best reference day is February 20, 2025, whereas customers nearest to Kentville CDA CS, the best reference day is March 13, 2025, and alternatively for Yarmouth A, the best reference day is February 27, 2025. A comparison between reference day and event day in Figure 12 shows the temperature profile for a 24-hour period prior to the March 11 morning event which started at 7:00 AM.

Figure 12: CPP Event Reference Day Temperature Profile Example



From Figure 12, it is clear that the temperature on the reference day and event day are similar with a mean absolute error (MAE) of 2.24 °C, root mean square error (RMSE) of 2.52 °C, mean bias error (MBE) of 1.97 °C and R^2 = 0.66. As well, the two 24-hour periods are positively correlated to each other (R = 0.81) with a difference in temperature of 1.3 °C at the beginning of the event.

3 Residential TOU Tariff Impacts

This section presents the analysis results for load and economic impacts of Residential TOU tariffs for all cohorts in Phase 4. The goal of the residential TOU pilot is to encourage customers to shift their electricity usage from peak periods to off-peak periods when system utilization is typically lower. This is done by presenting customers with the opportunity to lower their energy bills if they participate in load shifting. The price differential is derived from system savings created in the near-term in the form of reduced fuel and purchased power costs, and over the longer-term in the form of avoided generation, transmission, and distribution infrastructure costs.

The impacts of the TOU Tariff are evaluated within this section. Table 9 summarizes the characteristics of the residential TOU participants that were included in the analysis of the load and economic impacts. Notably, the number of TOU participants in Cohort 4 is almost three times larger than that in cohorts 1, 2, and 3 combined. Also, participants with steady electric heating system are more prevalent than participants with other heating types, while those with de-electrified heating are the least frequent among TOU participants in Phase 4.

Table 9: Summary of Residential TOU Sample Size[7]

Parameter	Cohort 1	Cohort 2	Cohort 3	Cohort 4	All
Sample Size	430	190	1,016	3,302	4,938
Heating Type					
Steady Electric	48%	65%	61%	61%	60%
Steady Non-Electric	26%	18%	22%	25%	24%
Electrified	22%	11%	11%	9%	10%
De-Electrified	4%	6%	6%	5%	6%
Region					
HRM	61%	58%	58%	58%	58%
Rest of Nova Scotia	39%	42%	42%	42%	42%

3.1 Load & Usage Impacts

This section presents and discusses the electrical load impact from the residential TOU Tariff.

3.1.1 Change in Load during Peak Periods

Table 10 summarizes the results of the analysis for morning and evening TOU peak hours for each cohort and for all cohorts combined. The average load reductions are presented along with their margin of error (MoE) at a 90% confidence level. While all cohorts exhibit statistically significant load reduction during morning and evening peak hours, TOU participants achieved slightly higher load reduction during the evening peak hours. Overall, TOU participants demonstrated load reductions of 0.15 kW and 0.17 kW, corresponding to relative load reductions of 7.4% and 7.9% during morning and evening periods, respectively. The overall average load reduction across all residential TOU participants is 0.16 kW.

[7] Sample size in this table differs from the participation summary found in Table 5 as some participants are removed due to not meeting AMI data criteria necessary for the regression analysis (refer to cleaning steps in Table 69)

Table 10: Change in Load during TOU Peaks for Residential TOU Participants

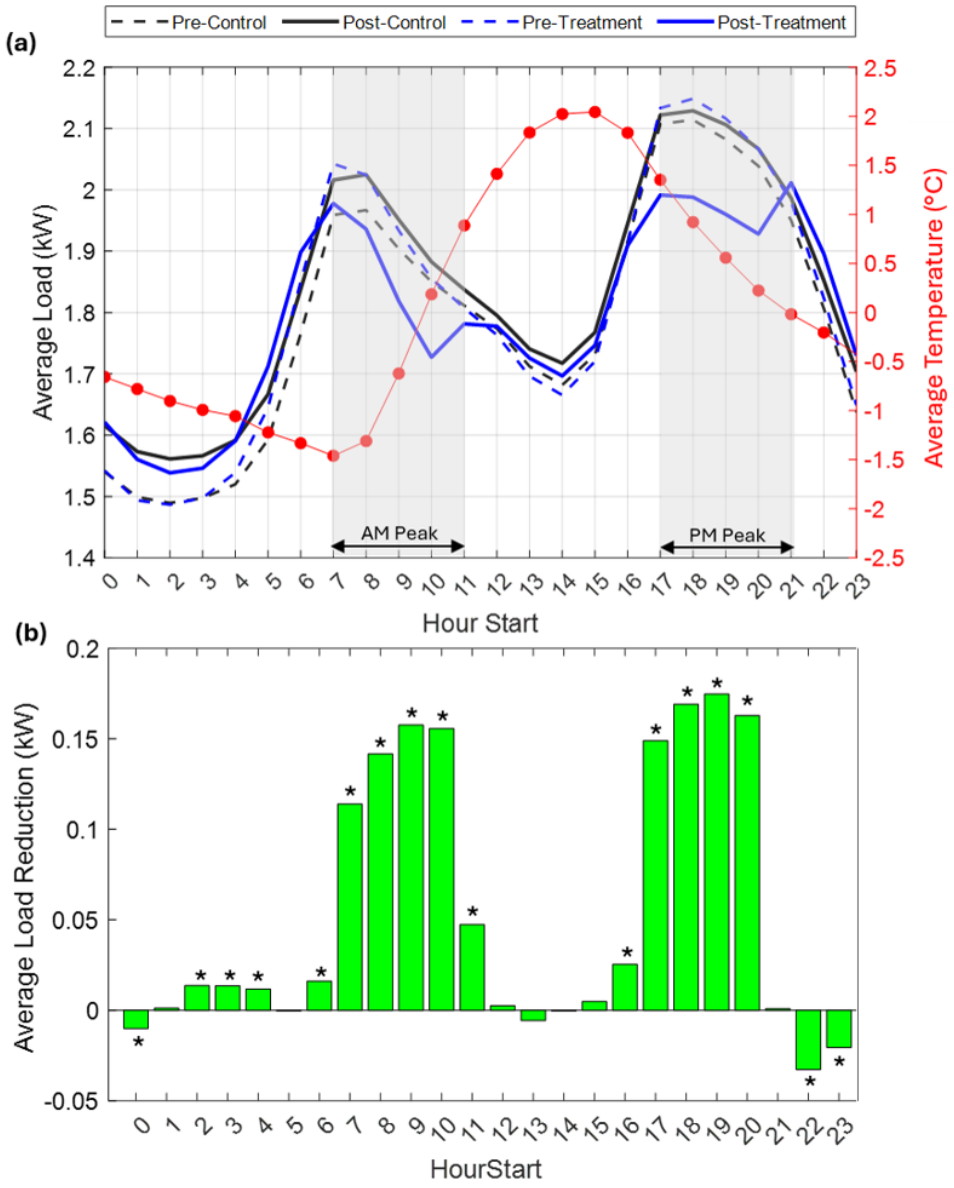
Parameters	Morning Peak Periods					Evening Peak Periods				
	Cohort 1	Cohort 2	Cohort 3	Cohort 4	All	Cohort 1	Cohort 2	Cohort 3	Cohort 4	All
Avg. Load Reduction (kW)[a]	0.18 ± 0.01	0.28 ± 0.02	0.14 ± 0.01	0.13 ± 0.01	0.15 ± 0.01	0.20 ± 0.01	0.31 ± 0.02	0.20 ± 0.01	0.14 ± 0.01	0.17 ± 0.01
Avg. Load – Residential TOU Participants Pre-Pilot (kW)	1.9	2.3	2.0	1.9	2.0	2.1	2.4	2.2	2.1	2.1
Relative Avg. Load Reduction (%)[a]	9.2%	12.3%	7.1%	6.7%	7.4%	9.7%	13.0%	9.2%	6.8%	7.9%
Significance (p_Value≤0.05)	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓

[a] Positive values represent 'Load Reduction' and Negative values represent 'Load Increase.'

Figure 13a illustrates the load profiles for residential TOU participants and the control group during the pre-pilot and pilot periods, along with the corresponding variation in outdoor temperature. Additionally, it highlights that residential TOU participants (post-treatment, blue line) exhibit load shifts during morning and evening peak hours, compared to the post-control group (black line).

Figure 13b shows the hourly load reduction by residential TOU customers that exhibit significant increase in load reductions during morning and evening peak hours. It indicates significant load shifts by TOU participants during TOU peak periods.

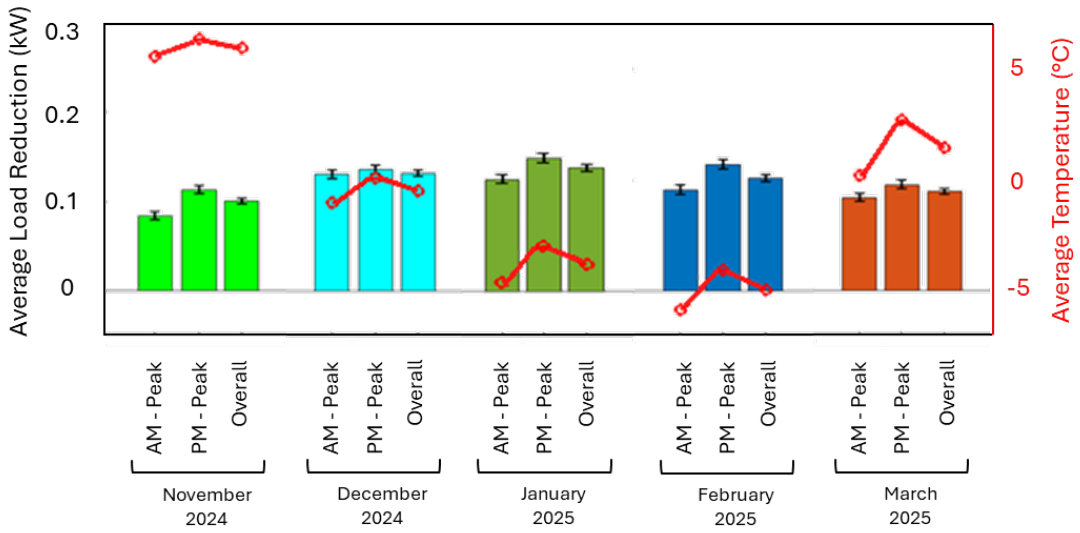
Figure 13: (a) Winter Hourly-Average Load Shapes for Residential TOU Participants (pre/post, treatment/control) with Average Outdoor Temperature; (b) Hourly Average Load Reduction (kW)



* Statistically Significant (p_Value≤0.05)

Figure 14 illustrates the impact of residential TOU in terms of average load reduction (kW), together with the average outdoor temperature (°C) during peak hours by month over the Winter period from November 2024 to March 2025. Residential TOU participants demonstrated statistically significant load reductions during both morning and evening peak hours across all Winter months. Notably, TOU participants exhibit the highest load reduction during evening peak hours in January and February when they experienced the coldest weather.

Figure 14: Average Load Reduction (kW) and Average Temperature during Residential TOU Peak Periods in Winter for the Months of November, December, January, February, and March



Change in Load by Space Heating Classes during TOU Peak Hours

Table 11 summarizes the average load reductions during morning and evening TOU peak hours for space heating classes of all cohorts combined in Phase 4. The load reductions by all space heating classes are statistically significant. Specifically, the TOU participants with steady electric space heating system exhibit the highest average load reductions of 0.18 kW and 0.20 kW, corresponding to relative load reductions of 7%, during morning and evening peak hours, respectively. As expected, the TOU customers with steady non-electric space heating systems demonstrate the lowest absolute load reductions of 0.07 kW and 0.1 kW during morning and evening peak hours. The TOU participants who electrified their heating system, by transitioning from non-electric to electric space heating, exhibit load reductions of 0.07 kW and 0.14 kW during morning and evening peak hours.

Table 11: Change in Load during TOU Peak Hours during Non-Holiday Weekdays in Winter by Heating Class for Residential TOU Participants

Parameters	Morning				Evening			
	De-Electrified	Electrified	Steady Electric	Steady Non-Electric	De-Electrified	Electrified	Steady Electric	Steady Non-Electric
Avg. Load Reduction (kW)[a]	0.15 ± 0.01	0.07 ± 0.01	0.18 ± 0.03	0.07 ± 0.01	0.12 ± 0.01	0.14 ± 0.01	0.20 ± 0.01	0.10 ± 0.01
Avg. Load – Residential TOU Participants, Pre-Pilot (kW)	1.4	1.7	2.5	0.8	1.6	1.9	2.6	1.1
Relative Avg. Load Reduction (%)[a]	10.4%	4.3%	7.0%	8.2%	7.5%	7.0%	7.3%	9.8%
Significance (p_Value≤0.05)	✓	✓	✓	✓	✓	✓	✓	✓

[a] *Positive* values represent 'Load Reduction' and *Negative* values represent 'Load Increase'.

Change in Load by Region, Income Level, and Residents per Household

Figure 15 illustrates the average load reduction achieved by TOU participants according to the region of premises in Nova Scotia. While no significant difference in load reduction during morning hours is observed between participants in greater Halifax area and those located in the rest of Nova Scotia, the TOU participants in Halifax area exhibit higher load reduction during evening peak hours compared to those located in the rest of Nova Scotia. However, the difference of overall load reductions is not statistically significant between Halifax area and the rest of Nova Scotia.

Figure 15: Average Load Reduction during Morning and Evening Peak Hours for TOU Participants Located in the Greater Halifax Area and the Rest of Nova Scotia

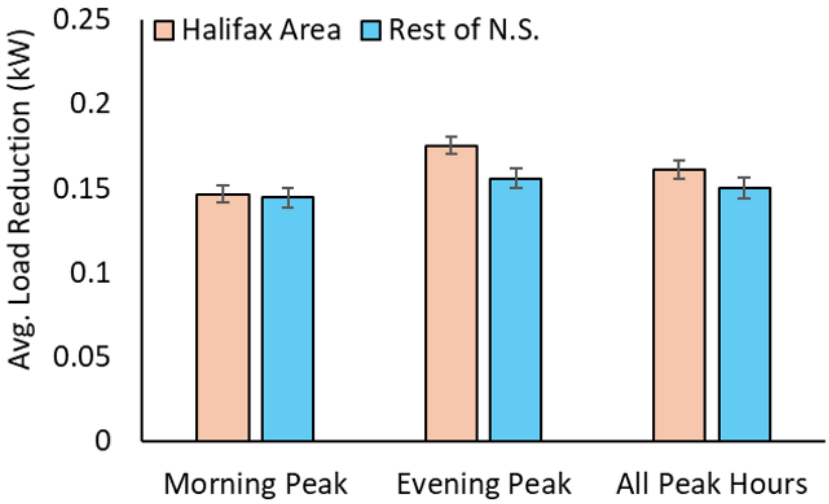
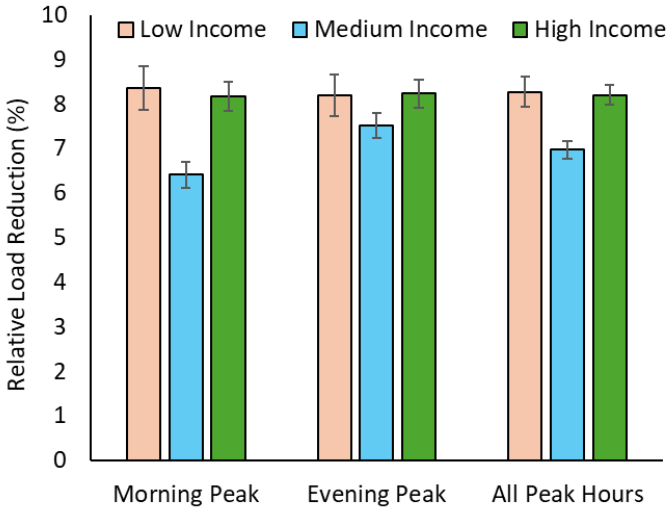


Figure 16 illustrates the average load reduction by income level (Low, Medium, and High-income levels), where TOU participants with lower, medium and higher income levels exhibit relative load reductions of 8.3%, 7.0%, and 8.2% corresponding to overall load reductions of 0.15 kW, 0.14 kW, and 0.19 kW, respectively (Table 12) across TOU related periods.

Figure 16: Relative Average Load Reduction (%) by Income Levels of TOU Participants during Morning and Evening TOU Peak Hours as well as Overall across All Peak Periods



Notably from Figure 16, there is no discernable trend in relative load reduction (%) associated with change in income. However, when absolute load reductions are compared, higher income participants demonstrate statistically significantly higher load reductions (0.19 ± 0.01 kW) relative to low- (0.15 ± 0.01 kW) and medium-income (0.14 ± 0.01 kW) participants, respectively.

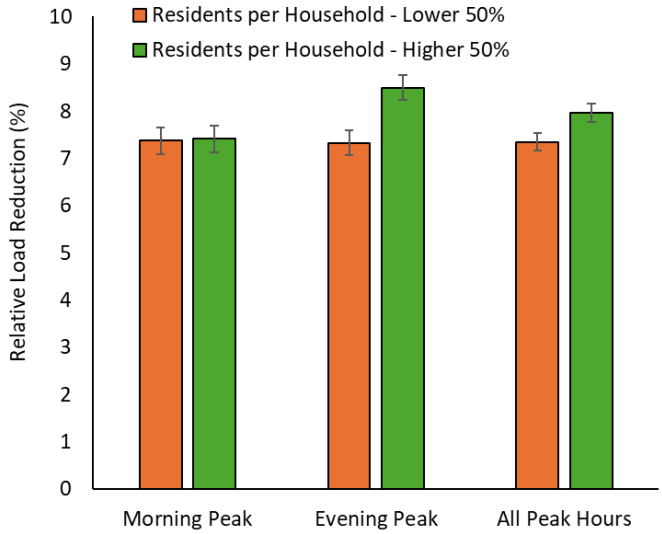
Table 12: Change in Load during TOU Peak Hours by Income Level for Residential TOU Participants

Parameters	Low-Income			Medium-Income			High-Income		
	AM Peak	PM Peak	All Peak Hours	AM Peak	PM Peak	All Peak Hours	AM Peak	PM Peak	All Peak Hours
Avg. Load Reduction (kW)[a]	0.14 ± 0.01	0.15 ± 0.01	0.15 ± 0.01	0.12 ± 0.01	0.16 ± 0.04	0.14 ± 0.01	0.18 ± 0.01	0.19 ± 0.01	0.19 ± 0.01
Avg. Load – Residential TOU Participants, Pre-Pilot (kW)	1.7	1.8	1.8	1.9	2.1	2.0	2.2	2.4	2.3
Relative Avg. Load Reduction (%)[a]	8.4%	8.2%	8.3%	6.4%	7.5%	7.0%	8.2%	8.2%	8.2%
Significance (p_Value≤0.05)	✓	✓	✓	✓	✓	✓	✓	✓	✓

[a] Positive values represent 'Load Reduction' and Negative values represent 'Load Increase.'

Figure 17 illustrates the load reduction by TOU participants according to residents per household, segmented at the lower 50% and higher 50% for the comparison. The households with more residents achieved an overall load reduction of 0.18 kW which is greater than 0.13 kW achieved by the lower households. It is worth noting that the average household size differs between the segments, with 2.03 residents in the lower 50% and 2.79 residents in the higher 50%.

Figure 17: Average Load Reduction (kW) by Residents-per-Household (lower 50% vs. higher 50%) for Morning and Evening TOU Peak Hours as well as All Peak Periods

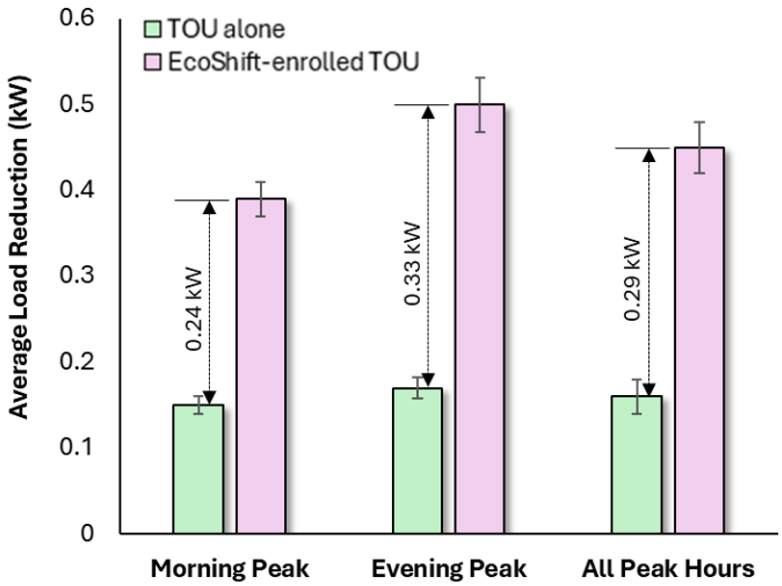


Change in Load with Eco Shift

E1's Eco Shift is a DR initiative offered separately from TVP and was implemented within subset of the TVP treatment participants who opted into both programs. It is designed to encourage load reduction during peak hours by connecting with smart devices that can automatically reduce electricity usage during peak demand periods. Refer to Attachment III: Methodology (Table 71) for a list of Eco Shift events.

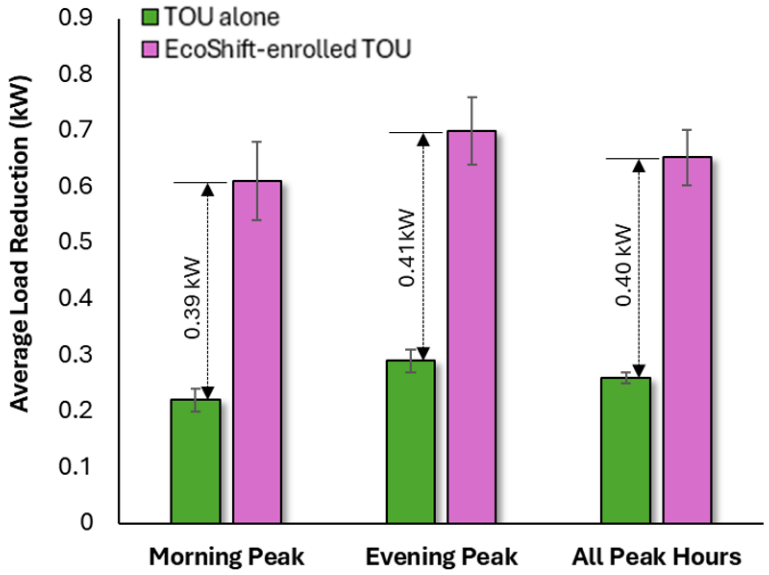
NS Power evaluated the overlapping effect of Eco Shift enrolled customers on TOU load impact during TOU peak periods without event calls, as well as the incremental load reduction due to Eco Shift event calls compared to non-Eco Shift residential TOU customers during Eco Shift events. The analysis uses a triple-difference (DDD) regression analysis (equation (8)) to estimate the incremental effect of overlapping Eco Shift enrollment on TOU impact. The analysis reveals that TOU participants that also enrolled in Eco Shift reduced their overall load by an additional 0.29 kW ± 0.01 kW during all TOU peak hours, where they reduced their load by additional 0.24 ± 0.01 kW and 0.33 kW ± 0.02 kW during morning and evening TOU peak hours, respectively (Figure 18). The analysis shows that the TOU program alone led to an overall load reduction of 0.15 ± 0.002 kW, indicating the overlapping Eco Shift-enrolled TOU participants achieved a greater overall load reduction of 0.44 kW. Refer to Figure 18 for both the TOU customers without Eco Shift (TOU alone) and TOU Enrolled Eco Shift load impacts.

Figure 18: Average Load Reductions for Residential TOU Participants vs. Eco Shift-Enrolled Residential TOU Participants during TOU Peak Hours



Furthermore, the analysis shows that TOU participants enrolled in Eco Shift demonstrated an additional load reduction of 0.40 ± 0.04 kW during Eco Shift events. Specifically, TOU participants reduced their load on average by an additional 0.39 ± 0.05 kW in the morning and 0.41 ± 0.04 kW in the evening (Figure 19). Participants experienced an overall load reduction of 0.26 ± 0.02 kW due to the TOU program alone during Eco Shift events. This indicates that Eco Shift–enrolled TOU participants achieved a total load reduction of 0.66 kW during Eco Shift events when combining both the TOU effect and the additional Eco Shift impact (Figure 19).

Figure 19: Load Reductions for Residential TOU Participants vs. Eco Shift-Enrolled Residential TOU Participants during Combined Peak-Event (TOU + Eco Shift) Morning and Evening Event Hours, Reflecting the Eco Shift Event Driven Additional Load Impact



In conclusion, the customers with overlapping participation in the Eco Shift program provide a statistically significant additional impact on load reduction, relative to TOU load impact alone. This effect was further enhanced during Eco Shift DR events.

3.1.2 Snapback Effect

While the TOU participants exhibit relatively small but statistically significant load increase of 0.014 kW during evening snapback period, they reduced their electricity usage by 0.013 kW during morning snapback hours, which is also statistically significant (Table 13). However, overall, participants experienced a statistically insignificant change in their load during morning and evening snapback periods (Table 13).

Table 13: Snapback Effect for Residential TOU Participants

Parameters	Avg. Load Reduction [a] (kW)	Significance (p_Value≤0.05)
Morning Snapback	0.013 ± 0.004	✓
Evening Snapback	-0.014 ± 0.005	✓
Overall Snapback	-0.002 ± 0.003	X

[a] Positive and Negative values represent 'Reduction' and 'Increase' in electricity usage, respectively.

3.1.3 Change in Load during Highest ANL Hours

Figure 20 depicts the distribution of Top 20, 50, and 88 highest ANL hours for residential TOU participants during morning peak, evening peak, and off-peak hours as well as weekends and holidays. As provided in Figure 20a-c, the majority of the highest ANL hours occurred during weekdays, and specifically on morning and evening peak hours.

Figure 20: Distribution of Top 20, Top 50 and Top 88 ANL Hours by Day Type (Weekday / Weekend) and Residential TOU Period

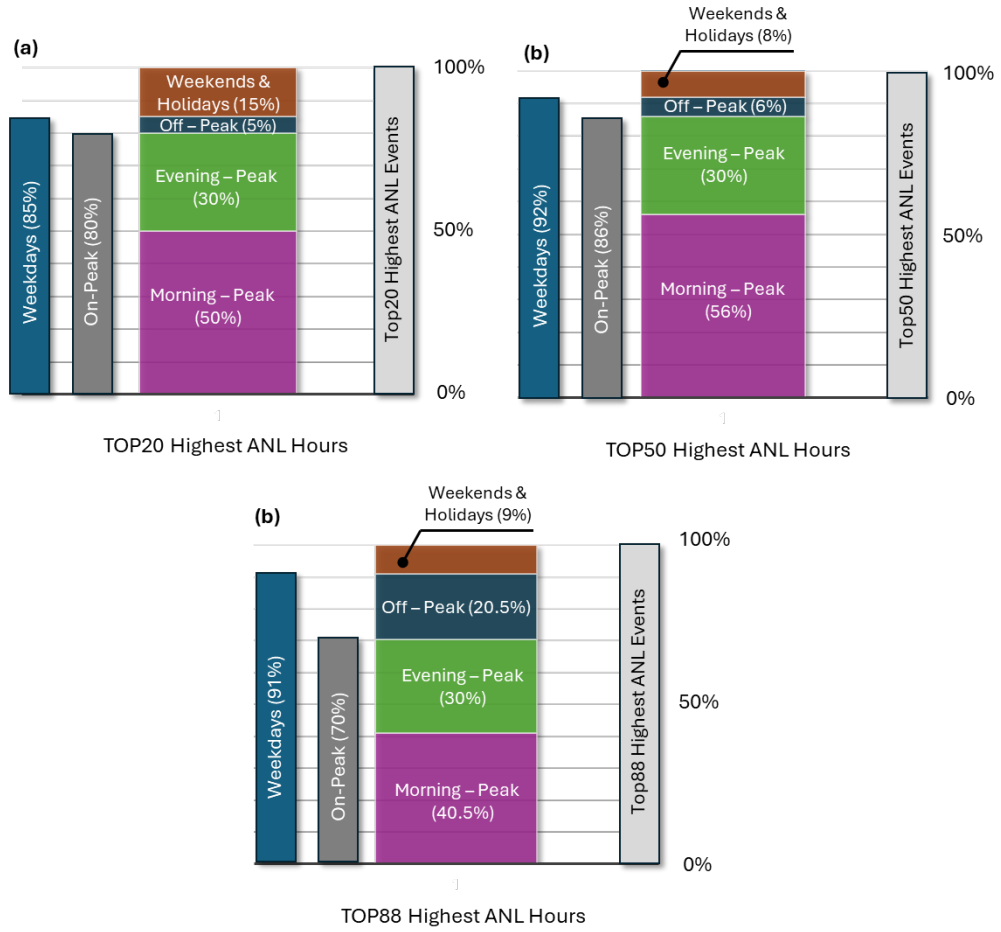


Table 14 summarizes the estimated changes in load during the highest ANL hours overall, as well as during ANL hours that coincide with TOU peak periods.

Results indicate that residential TOU participants exhibit statistically significant load reduction during the top 20, 50, and 88 highest ANL hours. When focusing specifically on ANL hours that coincide with TOU peak periods, participants achieved significant relative load reduction of approximately 6%, corresponding to absolute load reduction of 0.17 kW, during top 20, 50, and 88 hours that coincide with TOU peak hours, which are higher than their corresponding load reductions of 0.16 kW, 0.14 kW, and 0.13 kW during the highest ANL hours.

Table 14: Change in Load (kW) during Highest Winter ANL Hours for Residential TOU Participants

Parameters	Highest ANL Hours			ANL Hours Coincide TOU Peak Periods		
	Top 20	Top 50	Top 88	Top 20	Top 50	Top 88
Avg. Load Reduction (kW)[a]	0.16 ± 0.04	0.14 ± 0.03	0.13 ± 0.02	0.17 ± 0.03	0.17 ± 0.03	0.17 ± 0.02
Avg. Load – Residential TOU Participants, Pre-Pilot (kW)	2.86	2.78	2.70	2.85	2.76	2.72
Relative Avg. Load Reduction (%)[a]	5.6%	5.2%	4.8%	6.0%	5.9%	6.2%
Significance (p_Value≤0.05)	✓	✓	✓	✓	✓	✓

[a] Positive values represent 'Load Reduction' and Negative values represent 'Load Increase.'

3.1.4 Change in Usage

Table 15 summarizes changes in daily electricity usage level for cohorts 1 to 4 and all cohorts combined during non-holiday weekdays and holiday weekends in Winter. All cohorts exhibit statistically significant reduction in daily usage level during non-holiday weekdays in Winter. All cohorts reduced their daily usage during holiday weekends in Winter as well. Overall, all cohorts exhibit a statistically significant average load reduction of 1.39 kWh during non-holiday weekdays. Notably, TOU participants also demonstrated an average load reduction of 0.6 kWh on holidays and weekends, which is statistically significant.

Table 15: Change in Daily Electricity Usage (kWh/day) by Cohort for Residential TOU Participants

Parameters	Cohort 1	Cohort 2	Cohort 3	Cohort 4	All
Winter, Non-Holiday Weekdays					
Avg. Usage Reduction (kWh/day)[a]	1.71 ± 0.21	2.70 ± 0.31	1.64 ± 0.14	1.10 ± 0.08	1.39 ± 0.06
Avg. Usage – Residential TOU Participants, Pre-Pilot (kWh/day)	39.4	50.4	43.2	43.4	43.4
Relative Usage Reduction (%)[a]	4.3%	5.4%	3.8%	2.6%	3.2%
Significance (p_Value≤0.05)	✓	✓	✓	✓	✓
Winter, Weekends / Holidays					
Avg. Usage Reduction (kWh/day)[a]	0.86 ± 0.33	1.91 ± 0.48	1.11 ± 0.22	0.32 ± 0.12	0.60 ± 0.10
Avg. Usage – Residential TOU Participants, Pre-Pilot (kWh/day)	41.2	52.1	45.0	44.6	44.8
Relative Usage Reduction (%)[a]	2.1%	3.7%	2.4%	0.7%	1.4%
Significance (p_Value≤0.05)	✓	✓	✓	✓	✓
Non-Winter					
Avg. Usage Reduction (kWh/day)[a]	0.79 ± 0.08	0.53 ± 0.15	0.55 ± 0.06	n/a	0.54 ± 0.04
Avg. Usage – Residential TOU Participants, Pre-Pilot (kWh/day)	25.8	28.6	26.3		25.5
Relative Usage Reduction (%)[a]	3.1%	1.9%	2.1%		2.1%

[a] Positive values represent 'Usage Reduction' and Negative values represent 'Usage Increase.'

Table 16 presents changes in daily electricity usage levels by space heating. During non-holiday weekdays in Winter, TOU participants with electrified space heating exhibit insignificant change in their daily usage level. Notably, this group of participants exhibit a significantly larger daily usage increase of 1.01 kWh/day, corresponding to 3.5% daily usage increase, during holidays and weekends. In contrast, participants with de-electrified heating systems demonstrate a daily usage reduction of 0.75 kWh/day during non-holiday weekdays, while they exhibit insignificant change in their daily usage during holiday/weekends. Participants with steady electric heating systems achieved daily usage reductions of 3.5% and 2.0%, corresponding to electricity usage reductions of 1.96 kWh and 1.14 kWh, respectively, during non-holiday weekdays and holidays and weekends. TOU customers with steady non-electric heating systems exhibit daily usage reduction of 0.15 kWh/day during non-holiday weekdays, while increasing their usage by 0.46 kWh/day during holiday weekends in Winter. For all TOU participants combined, savings are statistically significant for all days throughout the year and add up to 300 kWh annually on average.

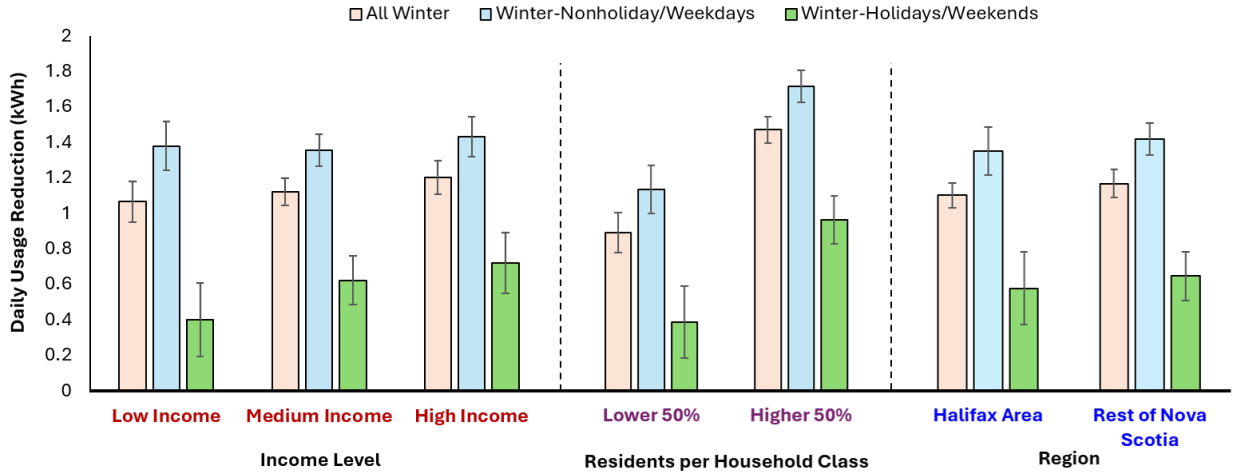
Table 16: Change in Daily Electricity Usage Level by Space Heating Type for All Cohorts of Residential TOU Participants

Parameters	De-Electrified	Electrified	Steady Electric	Steady Non-Electric
Winter, Non-Holiday Weekdays				
Avg. Usage Reduction (kWh/day)[a]	0.75 ± 0.20	-0.09 ± 0.14	1.96 ± 0.10	0.15 ± 0.07
Avg. Usage – Residential TOU Participants, Pre-Pilot (kWh/day)	38.5	27.7	55.4	20.4
Relative Usage Reduction (%)[a]	1.9%	-0.34%	3.5%	0.72%
Significance (p_Value≤0.05)	✓	X	✓	✓
Winter, Weekends / Holidays				
Avg. Usage Reduction (kWh/day) [a]	0.10 ± 0.31	-1.01 ± 0.22	1.14 ± 0.10	-0.46 ± 0.10
Avg. Usage – Residential TOU Participants, Pre-Pilot (kWh/day)	40.0	27.7	56.6	21.7
Relative Usage Reduction (%)[a]	0.2%	-3.5%	2.0%	-2.1%
Significance (p_Value≤0.05)	X	✓	✓	✓
Non-Winter				
Avg. Usage Reduction (kWh/day)[a]	0.90 ± 0.17	0.37 ± 0.10	0.74 ± 0.06	0.31 ± 0.08
Avg. Usage – Residential TOU Participants, Pre-Pilot (kWh/day)	24.5	22.5	29.5	21.6
Relative Usage Reduction (%)[a]	3.7%	1.7%	2.5%	2.1%
Significance (p_Value≤0.05)	✓	✓	✓	✓

[a] Positive values represent 'Usage Reduction' and Negative values represent 'Usage Increase.'

Further segmented changes in daily-usage level by income level, residents-per-household, and region, are shown in Figure 21. The participants from all segments above exhibit the highest daily load reduction (kWh/day) during non-holidays/weekdays. Notably, the households with higher 50% residents-per-household demonstrated significantly higher daily usage reduction during Winter compared to the households with lower 50% residents-per-household. In contrast, no statistically significant differences of daily usage reduction were observed among participants with low-, medium-, and high-income levels. Likewise, the daily usage reductions between TOU customers in Halifax area and those in the rest of Nova Scotia were not statistically different.

Figure 21: The Impact of Residential TOU Participants on Daily Usage Level (kWh/day) by Participants from Different Segments of Income-Level, Residents-per-Household, and Region



3.2 Economic Impacts

This section presents and discusses the impact of residential TOU tariffs on the electricity bill as well as price elasticity.

3.2.1 Change in Electricity Bills

Table 17 summarizes the applicable tariffs used for residential TOU impact on billing. Tariff details can be found in Attachment I: Riders and Tariff Structure.

Table 17: Tariffs Used for Analyzing Residential TOU Impact on Electricity Bill

Customer Type and Period	Applicable Tariff
Control, Pre-Pilot	Domestic Standard Tariff
Control, Pilot	Domestic Standard Tariff
Treatment, Pre-Pilot	Domestic Standard Tariff
Treatment, Pilot	Domestic TOU Tariff

Table 18 presents the bill impact for residential TOU, where participants exhibit an overall annual average bill saving of $0.30 per day, corresponding to 5.5% of average annual bill. This amount of annual bill saving is statistically significant. The residential TOU participants achieved an average bill savings of $1.54 per day during non-Winter, corresponding to 32.6% of average non-Winter bill. The non-Winter savings are primarily due to a reduced rate per kWh during the non-Winter period (11.426 ¢/kWh under the TOU Tariff) compared to 16.931¢/kWh for the Domestic SOR. In contrast, the TOU participants experienced an overall bill increase of $1.34 per day during Winter despite significant load reduction (Table 10). This is because the TOU rate during peak hours is approximately

twice the TOU rate during off-peak hours,[8] for which peak load reductions and energy savings could not fully offset increase in rate during the Winter period.

Table 18: Change in Daily Electricity Bill for All Cohorts of Residential TOU Participants

Parameters	Winter Non-Holiday Weekdays	Winter Holiday/ Weekends	Winter Overall	Non-Winter	Annual Average
Avg. Bill Savings ($/day)[a]	-2.05 ± 0.01	0.12 ± 0.01	-1.34 ± 0.01	1.54 ± 0.04	0.30 ± 0.01
Avg. Bill – Residential TOU Participants, Pre-Pilot ($/day)	8.1	8.3	8.1	4.7	5.4
Relative Avg. Bill Savings (%)[a]	-25.5%	1.5%	-16.5%	32.6%	5.5%
Significance (p_Value≤0.05)	✓	✓	✓	✓	✓

[a] *Positive* values represent 'Bill Savings' and *Negative* values represent 'Bill Increase.'

The analysis reveals that the type of space heating has significant influence on the bill impact for the TOU participants. While TOU participants with all space heating types experienced significant increases in bills during Winter season, they achieved significant bill savings during non-Winter, which are statistically significant. Overall, all space heating types exhibit significant annual bill savings ranging from $120 to $164. Notably, TOU participants with electrified space heating exhibit an average annual bill savings of $153, refer to Table 19. While TOU participants who switched heating types show a change in electric costs, this analysis does not account for additional fuel costs or fuel savings for non-electric heating sources they may have incurred.

[8] TOU rates were 32.12 ¢/kWh during peak hours and 16.931 ¢/kWh during off-peak hours.

Table 19: Change in Daily Electricity Bill by Space Heating Type for All Cohorts of Residential TOU Participants

Parameters	De-Electrified	Electrified	Steady Electric	Steady Non-Electric
Winter				
Avg. Bill Savings ($/day)[a]	-1.12 ± 0.02	-1.49 ± 0.02	-1.61 ± 0.01	- 0.76 ± 0.01
Avg. Bill – Residential TOU, Pre-Pilot ($/day)	7.3	5.2	10.3	3.8
Relative Avg. Bill Savings (%)[a]	-15.4%	-28.5%	-15.6%	-19.4%
Significance (p_Value≤0.05)	✓	✓	✓	✓
Non-Winter				
Avg. Bill Savings ($/day) [a]	1.56 ± 0.02	1.37 ± 0.01	1.71 ± 0.01	1.22 ± 0.01
Avg. Bill – Residential TOU, Pre-Pilot ($/day)	4.6	4.2	5.3	4.0
Relative Avg. Bill Savings (%)[a]	34.3%	32.9%	32.5%	30.5%
Significance (p_Value≤0.05)	✓	✓	✓	✓
Annual				
Avg. Bill Savings ($/day)[a]	0.45 ± 0.02	0.42 ± 0.01	0.33 ± 0.01	0.38 ± 0.01
Avg. Bill – Residential TOU, Pre-Pilot ($/day)	5.6	4.3	7.4	3.9
Relative Avg. Bill Savings (%)[a]	8.0%	9.9%	4.5%	9.5%
Significance (p_Value≤0.05)	✓	✓	✓	✓

[a] Positive values represent 'Bill Savings' and Negative values represent 'Bill Increase.'

3.2.2 Price Elasticity

Residential TOU participants' responsivity to electricity prices ($/kWh) was evaluated by estimating daily price elasticity during non-holiday weekdays in Winter season, as well as the Inter-period Substitution Price Elasticity during Winter season. Daily Price Elasticity reflects the change in overall daily electricity usage caused by changes in the average daily price ($) per kWh. It is expressed as the percent (%) change in the average electricity usage associated with a 1% increase in the daily average energy price. Inter-period Substitution Price elasticity reflects the participants' ability to substitute more expensive electricity usage during TOU peak hours with less expensive off-peak hours. It is expressed as the percent (%) change in the ratio of peak-to-off-peak average load associated with a 1% increase in the peak-to-off-peak price ratio.

The analysis reveals a daily price elasticity of -1.05 (± 0.1) during non-holiday weekdays in Winter, implying that for 1% increase in the average daily electricity price per kWh, the average daily electricity usage decreases by 1.05% during non-holiday weekdays in Winter. The inter-period substitution elasticity is estimated at -0.14 (± 0.001), indicating that a 1% increase in the ratio of peak-to-off-peak rates can lead to a decrease of 0.14% in the peak-to-off-peak load ratio by the residential TOU customers, which is statistically significant.

4 Residential CPP Tariff Impacts

This section presents the analysis results for load and economic impacts of the Domestic CPP Tariff for all cohorts in Phase 4. The goal of the residential CPP pilot is to encourage customers to shift their electricity usage during CPP events to the non-event periods when system utilization is lower, thereby providing DR capacity. This is done by presenting customers with options to lower their energy bills if they participate in load shifting. The price differential is derived from system savings created in the near-term in the form of reduced fuel and purchased power costs, and over the longer-term in the form of avoided generation, transmission and distribution infrastructure costs.

The impacts of CPP Tariff and the 14 events during Phase 4 (April 1, 2024 to March 31, 2025) are evaluated within this section. Table 20 presents the CPP events along with the Starting and Ending times, average outdoor temperature, and the weekday status.

Table 20: List of CPP Events and Their Corresponding Starting/Ending Times, Average Outdoor Temperature, and Weekday Status

Event Number	Event Date	Event Start Time (Hour)	Event End Time (Hour)	Average Outdoor Temperature (°C)[c]	Weekday Status[a]
1	2024-12-04	17:00	21:00	-3.6	NHW
2	2024-12-15	17:00	21:00	-2.5	Weekend
3	2024-12-20	7:00	11:00	-2.9	NHW
4	2024-12-22	17:00	21:00	-9.5	Weekend
5[b]	2024-12-23	7:00	11:00	-9.0	NHW
6[b]	2024-12-23	17:00	21:00	-9.0	NHW
7	2025-01-21	17:00	21:00	-9.1	NHW
8	2025-01-22	7:00	11:00	-13.1	NHW
9	2025-02-02	17:00	21:00	-9.9	Weekend
10	2025-02-05	17:00	21:00	-12.2	NHW
11	2025-02-06	7:00	11:00	-11.0	NHW
12	2025-03-04	7:00	11:00	-7.8	NHW
13	2025-03-10	7:00	11:00	-2.5	NHW
14	2025-03-11	7:00	11:00	-3.9	NHW

[a] NHW: Non-Holiday Weekdays.

[b] Double events in the same day.

[c] Average temperature of all events was -7.6 °C

Table 21 below summarizes the characteristics of the residential CPP participants that were included in the analysis of the load and economic impacts. As seen in Table 5, the number of CPP participants in Cohort 4 is much larger than that in Cohort 1, Cohort 2 and Cohort 3.

Table 21: Summary of Residential CPP Sample Size[9]

Parameters	Cohort 1	Cohort 2	Cohort 3	Cohort 4	All
Sample Size	161	75	468	1,606	2,310
Heating Type:					
Steady Electric	75%	79%	60%	62%	63%
Steady Non-Electric	9%	8%	23%	23%	21%
Electrified	12%	5%	11%	10%	10%
De-Electrified	4%	8%	6%	5%	6%
Region:					
Greater Halifax	73%	70%	57%	60%	59%
Rest of Nova Scotia	27%	30%	43%	40%	41%

4.1 Load & Usage Impacts

This section presents and discusses the electrical load impact from the Domestic CPP Tariff.

4.1.1 Change in Load during Peak Periods

Table 22 summarizes the results of the analysis for morning and evening CPP events for each cohort and all participants combined. The average load reduction metrics are presented along with their MoE at a confidence level of 90%. While all cohorts exhibit statistically significant load reduction during morning and evening CPP events, the results from cohort 4 show lower MoE 90% due to the higher number of participants in that cohort. The smaller MoE indicates the improved reliability of the results for load reductions. Overall, CPP participants demonstrated load reductions of 0.61 kW and 0.77 kW, corresponding to 25.4% and 28.5% relative load reductions, during morning and evening CPP events in Phase 4, respectively. The overall average load reduction across all residential CPP participants and events is 0.69 kW.

[9] Sample size in this table differs from the participation summary found in Table 5 as some participants are removed due to not meeting AMI data criteria necessary for the regression analysis (refer to cleaning steps in Table 69).

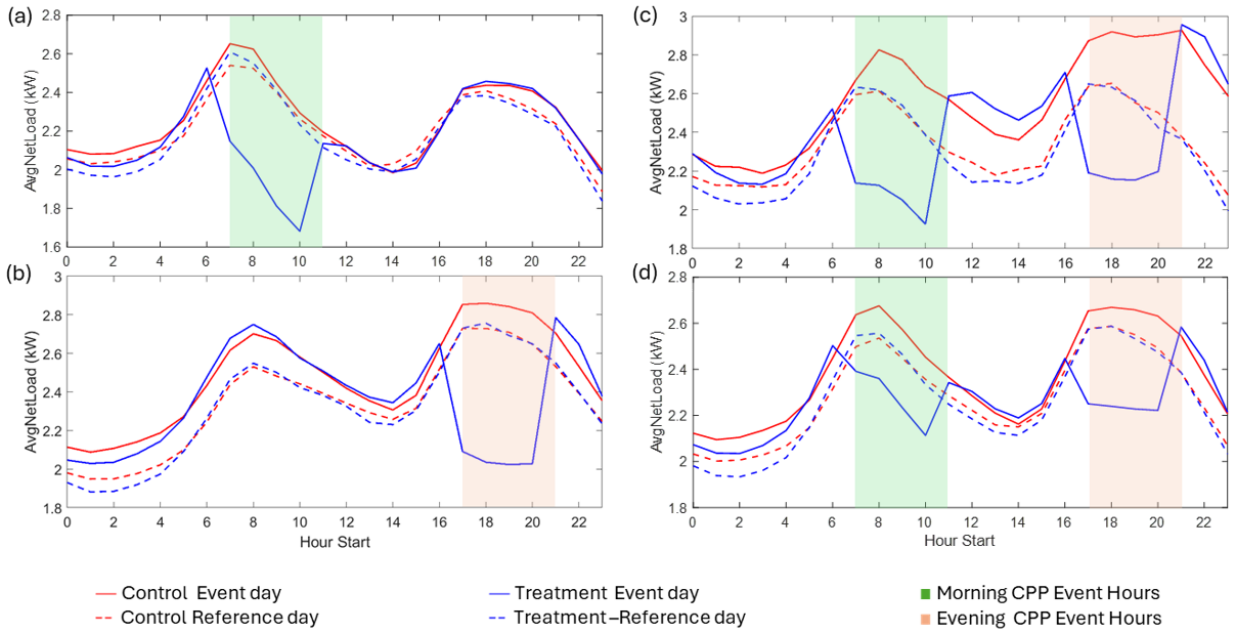
Table 22: Change in Load during CPP Events for Residential CPP Participants

Parameters	Morning Events					Evening Events				
	Cohort 1	Cohort 2	Cohort 3	Cohort 4	All	Cohort 1	Cohort 2	Cohort 3	Cohort 4	All
Avg. Load Reduction [a] (kW)	0.68 ± 0.10	1.22 ± 0.16	0.62 ± 0.06	0.60 ± 0.03	0.61± 0.03	0.85 ± 0.10	1.60 ± 0.60	0.88 ± 0.06	0.70 ± 0.03	0.77± 0.03
Avg. Load – Residential CPP Participants, Pre-Pilot (kW)	2.8	3.3	2.6	2.4	2.5	2.9	3.5	2.8	2.6	2.7
Relative Avg. Load Reduction[a] (%)	24.3%	36.9%	23.8%	23.9%	25.4%	29.3%	46.7%	31.5%	26.9%	28.5%
Significance (p_Value≤0.05)	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓

[a] Positive values represent 'Load Reduction' and Negative values represent 'Load Increase.'

Figure 22 illustrates the daily load profile for residential CPP participants as well as the control group during event day and reference day with morning events only, evening events only, both morning and evening events, and for all event days combined. The residential CPP participants exhibit significant load shifts during morning, evening as well as double event periods, compared to reference days.

Figure 22: Load Shapes for Residential CPP Participants on Event Days (a) with Morning Only Events, (b) with Evening Only Events, (c) with Double-Event, and (d) for All Event Days



Change in Load by Space Heating Classes During Peak Events

Table 23 summarizes the average load reductions during morning and evening events for space heating classes of all cohorts combined in Phase 4. It is important to note that, since load reductions are calculated by comparing event and reference days during the 2024/25 Winter, the change in space heating type between the baseline and the pilot period does not directly impact load reduction results in the DiD analysis.

Table 23: Change in Load during CPP Events by Heating Class for Residential CPP Participants

Parameters	Morning				Evening			
	De-Electrified	Electrified	Steady Electric	Steady Non-Electric	De-Electrified	Electrified	Steady Electric	Steady Non-Electric
Avg. Load Reduction [a] (kW)	0.57 ± 0.10	0.66 ± 0.08	0.74 ± 0.03	0.18 ± 0.02	0.74 ± 0.10	0.83 ± 0.08	0.92 ± 0.03	0.30 ± 0.03
Avg. Load – Residential CPP Participants, Pre-Pilot (kW)	2.4	2.4	3.1	0.8	2.0	2.6	3.3	1.2
Relative Avg. Load Reduction[a] (%)	27.6%	32.4%	24.0%	22.0%	36.9%	31.7%	28.2%	26.0%
Significance (p_Value≤0.05)	✓	✓	✓	✓	✓	✓	✓	✓

[a] Positive values represent 'Load Reduction' and Negative values represent 'Load Increase.'

Change in Load per Critical Peak Event

Figure 23a illustrates the average load reduction (kW) per CPP event date for all Phase 4 cohorts, along the corresponding event-average outdoor temperature (°C). The residential CPP participants exhibit significant load reduction across all event days. Three events which occurred during weekends are marked as H/W. The CPP participants exhibit an average load reduction of 0.76 kW during the weekends, which is comparable to the average load reduction of 0.67 kW during all non-holiday weekdays.

Figure 23b presents the disaggregated average load reduction by morning and evening events on CPP event days. Overall, CPP participants exhibit higher average load reductions during evening events than morning events. Notably, CPP participants achieved the largest average load reduction of 0.9 kW during the evening event on February 05, 2025, when the temperature was -12 °C. In contrast, the participants demonstrated the smallest load reduction of 0.46 kW on March 10, 2025 when the temperature was -3 °C. Refer to Section 4.1.5 for the effect of temperature on CPP load reduction.

Figure 23: (a) Average Load Reduction (kW) per CPP Event along with Average Event Temperature (°C), and (b) Average Load Reduction per CPP Event Date by Morning, Evening, or Morning and Evening CPP Event

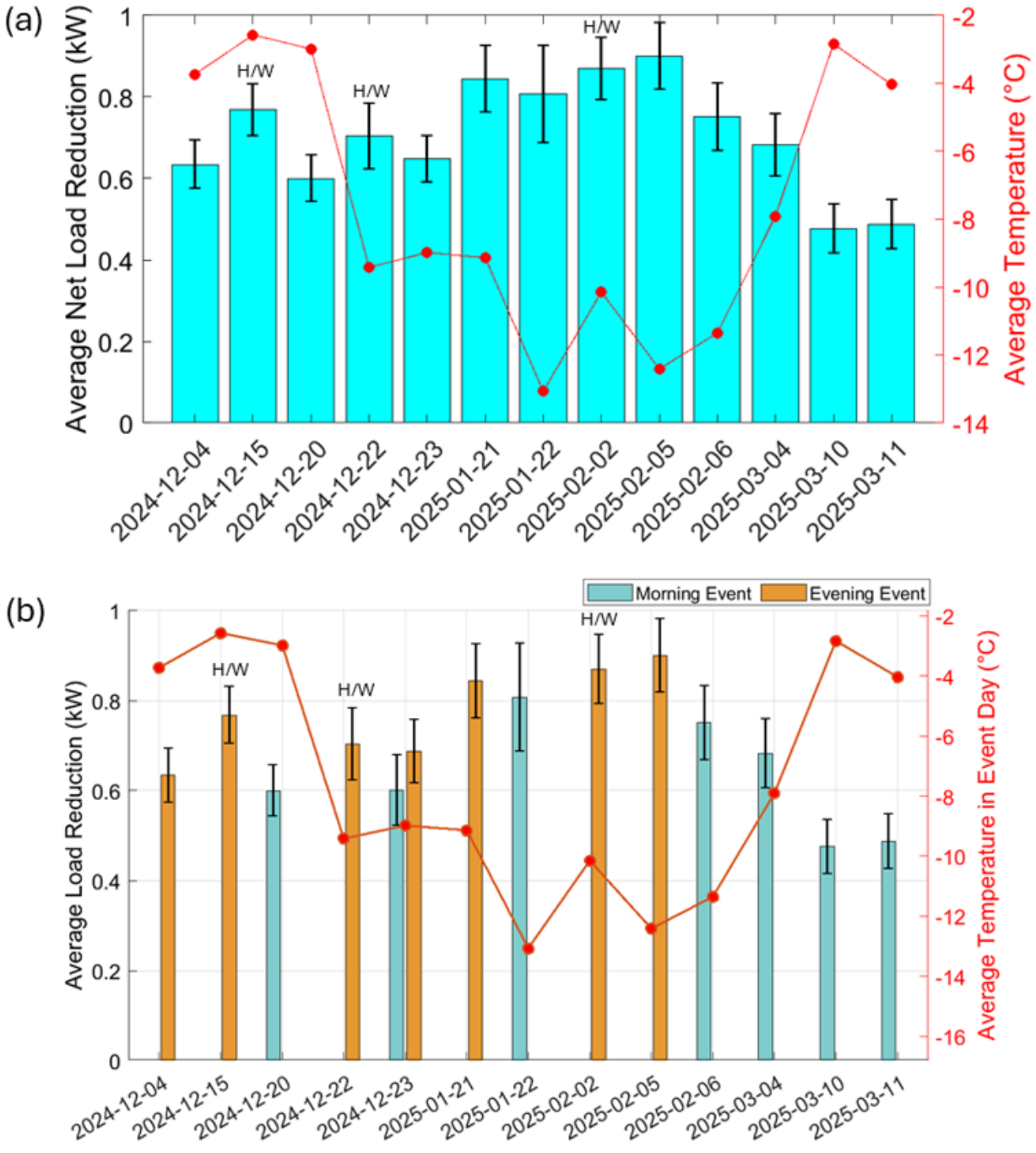


Figure 24 depicts the variations in the average hourly load reduction during each peak event. The trend for most events is that load reduction improves from the first to the second hour, on average is sustained from the second to the third hour and tapers off from the third to the fourth hour.

Figure 24: Average Hourly Load Reduction for CPP Event Change in Load by Region, Income Level, and Residents per Household

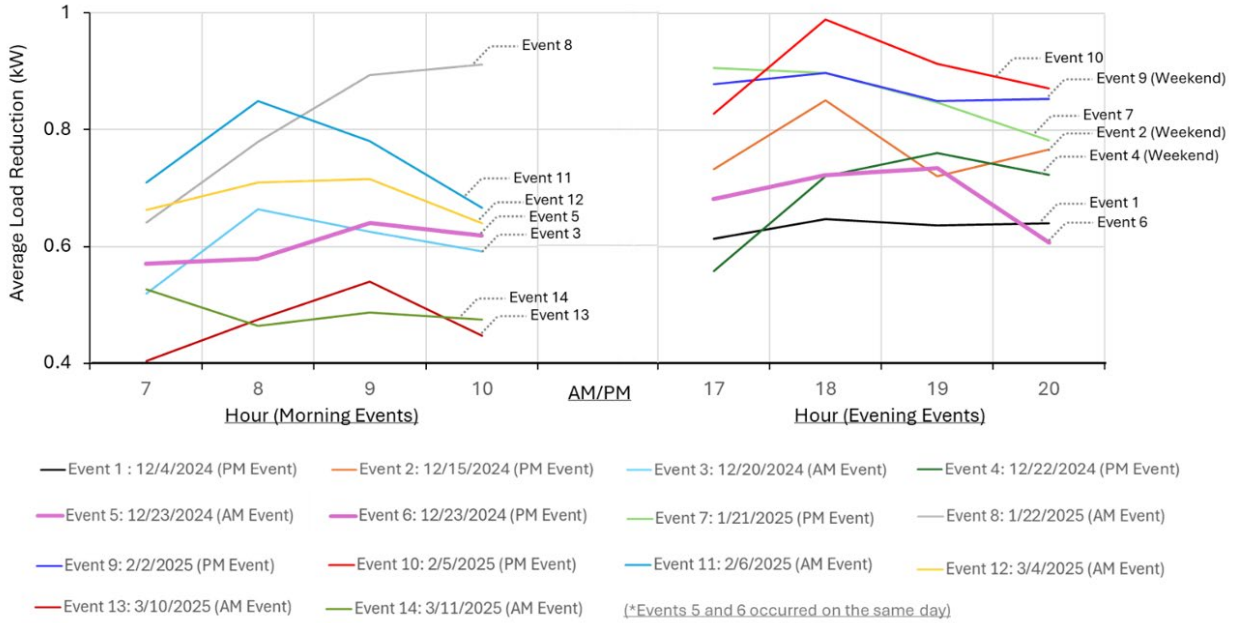


Figure 25 depicts the average load reduction achieved by CPP participants according to the region of premises in Nova Scotia, where CPP customers located in Halifax Area exhibit a statistically significant higher load reduction compared to those in the rest of Nova Scotia.

Figure 25: Average Load Reduction during Morning and Evening CPP Events for Residential CPP Participants Located in the Greater Halifax Area and the Rest of Nova Scotia

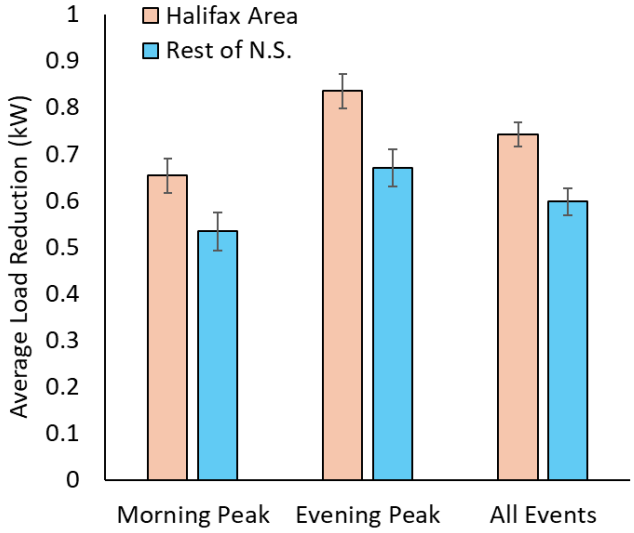
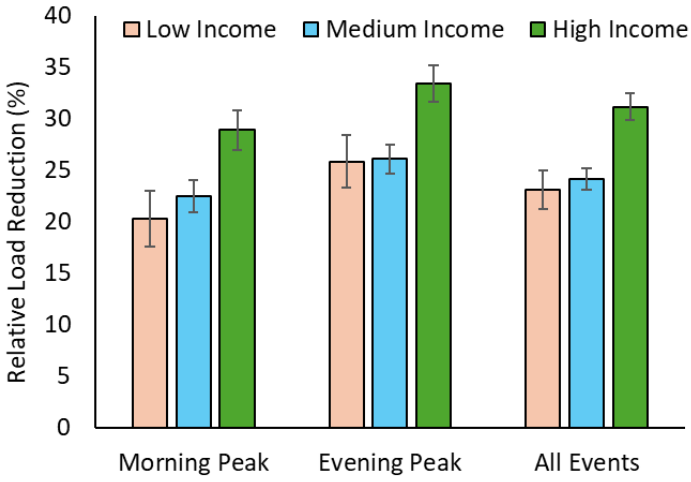


Figure 26 illustrates the average load reduction by CPP participants by income level (low-, medium- and high-income levels).

Figure 26: Relative Average Load Reduction (%) by Income Levels of Residential CPP Participants during Morning and Evening Events as well as Overall across All Peak Periods



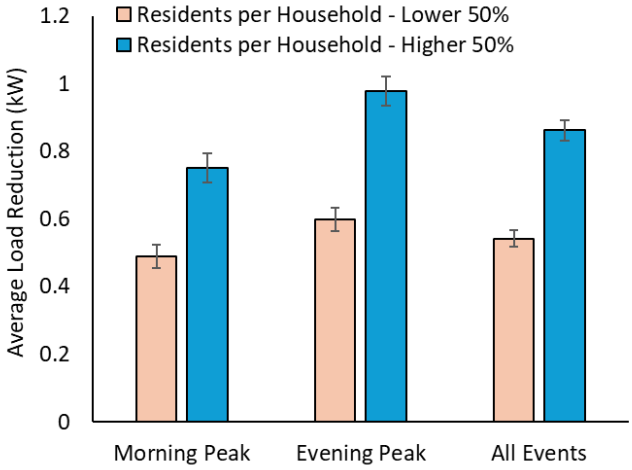
CPP customers with higher income levels achieved a higher relative load reduction of 31% overall, corresponding to 0.88 kW (Table 24), compared to CPP participants with low- and medium-income levels that demonstrated relative load reductions of 23% and 24%, respectively.

Table 24: Change in Load during CPP Events by Income Level for Residential CPP Participants

Parameters	Low-Income			Medium-Income			High-Income		
	AM Event	PM Event	Overall	AM Event	PM Event	Overall	AM Event	PM Event	Overall
Avg. Load Reduction [a] (kW)	0.43 ± 0.06	0.61 ± 0.06	0.52 ± 0.04	0.55 ± 0.04	0.69 ± 0.04	0.62 ± 0.03	0.78 ± 0.05	1.01 ± 0.05	0.88 ± 0.04
Avg. Load – Residential CPP Participants, Pre-Pilot (kW)	2.1	2.4	2.2	2.5	2.6	2.6	2.7	3.0	2.8
Relative Avg. Load Reduction[a] (%)	20%	26%	23%	22.5%	26%	24%	29%	33%	31%
Significance (p_Value≤0.05)	✓	✓	✓	✓	✓	✓	✓	✓	✓
[a] Positive values represent 'Load Reduction' and Negative values represent 'Load Increase.'									

Figure 27 illustrates the load reduction by CPP participants according to Residents per Household, segmented at the Lower 50% and Higher 50% for the comparison. The households with more residents achieved an overall load reduction of 0.87 kW which is greater than 0.54 kW achieved by the lower 50% households. It is worth noting the average household size difference between these segments, 1.99 residents in the lower 50% and 2.79 residents in the higher 50%.

Figure 27: Average Load Reduction (kW) by Residents-per-Household (lower 50% vs. higher 50%) for Morning and Evening CPP Event Hours as well as All Event Hours



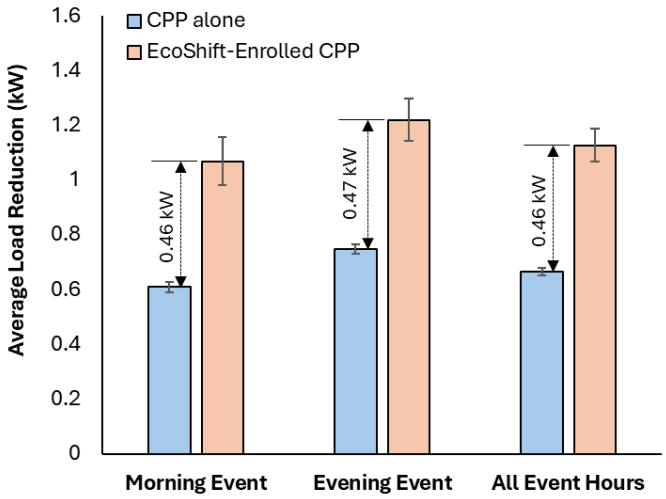
Change in Load with Eco Shift

E1's Eco Shift is a DR initiative offered separately from TVP and was implemented within subset of the TVP treatment participants who opted into both programs. It is designed to encourage load reduction during peak hours by connecting with smart devices that can automatically reduce electricity usage during peak demand periods. Refer to Attachment III: Methodology (Table 71) for a list of Eco Shift events.

NS Power evaluated the incremental load reduction due to Eco Shift compared to non-Eco Shift residential CPP customers during CPP event hours relative to reference days. NS Power used a triple-difference (DDD) regression analysis to estimate the incremental effect of Eco Shift on CPP impact, refer to equation (8). The analysis reveals that those CPP participants that enrolled in Eco Shift reduced their overall load by an additional 0.46 ± 0.05 kW during all CPP peak hours, where they reduced their load by additional 0.46 ± 0.07 kW and 0.47 ± 0.061 kW during morning and evening CPP hours, respectively (Figure 28). Also, the analysis shows that the CPP program alone led to an overall load reduction of 0.67 ± 0.013 kW, indicating that the CPP customers enrolled in Eco Shift program reduced their load by approximately 1.13 kW (Figure 28), combining both CPP and the incremental Eco Shift effect.

In conclusion, the Eco Shift program provides a statistically significant effect on enhancing load reduction among those CPP participants that also enrolled in the Eco Shift program.

Figure 28: Load Reductions for Residential CPP Participants vs. Eco Shift-Enrolled Residential CPP Participants during Combined Event (CPP + Eco Shift) Morning and Evening Event Hours, Reflecting the Eco Shift Additional Load Impact



Notably, due to there being only three CPP events without Eco Shift, occurring only in March, NS Power did not evaluate Eco Shift enrolled CPP customers during non-Eco Shift events as done in TOU.

4.1.2 Snapback Effect

The CPP participants exhibit relatively small but statistically significant snapback effects during morning, evening and double-event snapback periods, indicating significant increase in electricity usage during the four hours immediately following peak events. CPP participants experienced a snapback of 0.15 kW during the double-snapback periods, which is significantly greater than the snapback during only morning or evening snapbacks (Table 25).

Table 25: Snapback Effect for Residential CPP Participants

Parameters	Average Load Reduction [a] (kW)	Significance (p_Value≤0.05)
Morning Snapback	-0.04 ± 0.02	✓
Evening Snapback	-0.08 ± 0.03	✓
Double-Event Snapback[b]	-0.15 ± 0.05	✓
Overall Snapback	-0.06 ± 0.02	✓

[a] Positive and Negative values represent 'Reduction' and 'Increase' in electricity usage, respectively.

[b] Applies to the event day(s) with both morning and evening CPP peak hours.

4.1.3 Change in Load during Highest ANL Hours

Figure 29 illustrates the distribution of Top 20, 50 and 88 highest ANL hours for residential CPP participants during weekdays and weekends as well as across CPP events. The majority of the highest ANL hours occurred on weekdays. Specifically, 55%, 36% and 27% coincided with the top 20, 50, and 88 ANL hours, respectively, take place during peak periods (Figure 29). In addition,

approximately 40%, 28% and 21% of all CPP events, which coincided with the top 20, 50 and 88 ANL hours, respectively, occurred during weekdays, while only 15%, 8% and 6% of CPP events, which coincide with top 20, 50 and 88 ANL hours, took place on Weekends.

Figure 29: Distribution of Top 20, Top 50 and Top 88 ANL Hours by Day Type (Weekday / Weekend) and Residential CPP Events

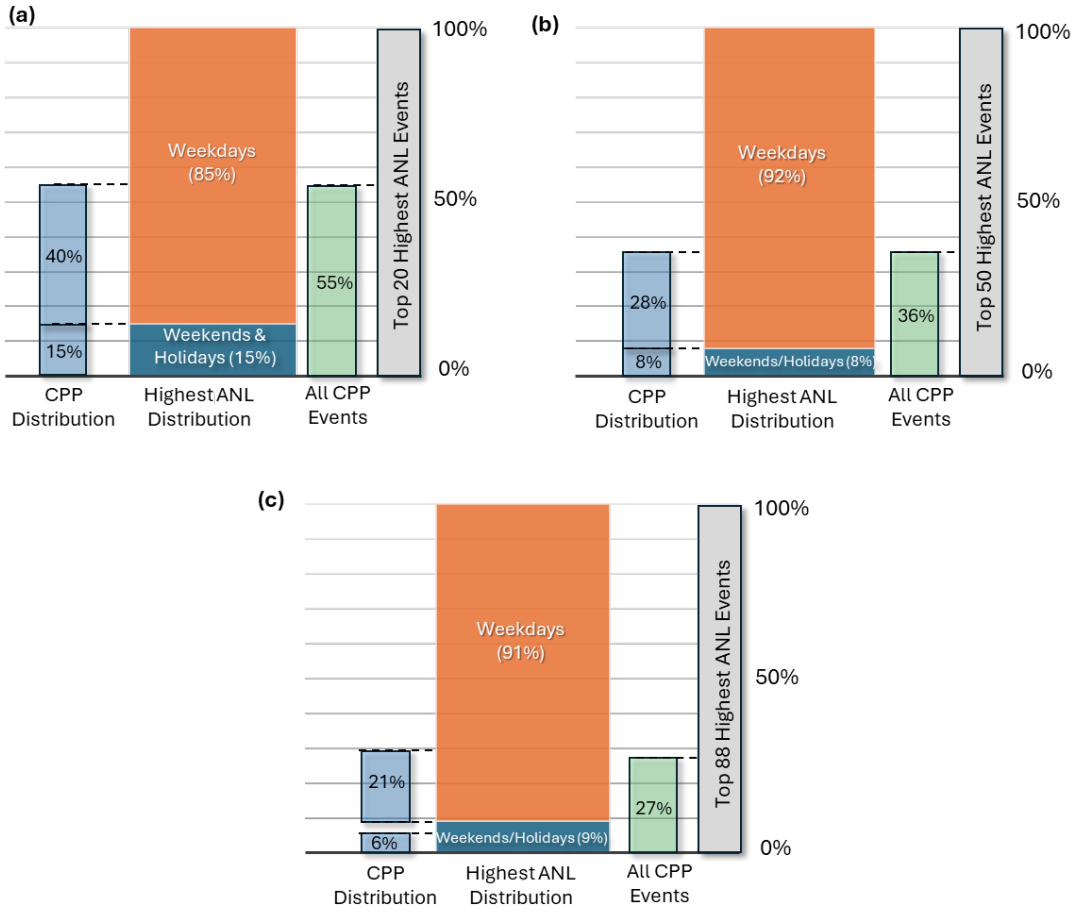


Table 26 summarizes the estimated changes in load for residential CPP participants during the highest ANL hours. Results indicate that participants achieved statistically significant load reductions during the top 20, 50, and 88 highest ANL hours. Focusing specifically on ANL hours that coincide with CPP peak periods, the CPP participants demonstrate slightly higher average load reductions during the top 20, 50 and 88 ANL hours compared to the corresponding highest ANL hours overall.

Table 26: Change in Load (kW) during Highest Winter ANL Hours for Residential CPP Participants

Parameters	Highest ANL Hours			ANL Hours Coincide with CPP Events		
	Top 20	Top 50	Top 88	Top 20	Top 50	Top 88
Avg. Load Reduction [a] (kW)	0.75 ± 0.07	0.63 ± 0.06	0.55 ± 0.04	0.85 ± 0.07	0.84 ± 0.06	0.80 ± 0.05
Avg. Load – CPP Participants, Pre-Pilot (kW)	2.9	2.9	2.8	2.9	2.9	2.9
Relative Avg. Load Reduction [a] (%)	26%	23%	19%	29%	28.5%	28%
Significance (p_Value≤0.05)	✓	✓	✓	✓	✓	✓

[a] Positive values represent 'Load Reduction' and Negative values represent 'Load Increase.'

4.1.4 Change in Usage

The change in daily usage levels was evaluated through two analyses. For the first analysis, the daily usage reduction during event days was estimated, when at least one CPP event occurred, compared to reference days. For the second analysis, the daily electricity usage levels for Winter and non-Winter days during the treatment period were evaluated compared to the pre-pilot period. Furthermore, both analyses were applied to estimate daily electricity usage changes for different heating classes.

The first analysis found out that for all event days combined, CPP participants reduced their daily electricity usage by an average of 1.7 kWh (± 1.3 kWh) compared to reference days, which is statistically significant. When disaggregated by cohort, the daily usage reductions by cohorts 1-3 were not statistically significant (Table 27). In contrast, cohort 4 exhibits a significant reduction of 1.6 kWh (± 1.5 kWh). When evaluated for different heating classes, the daily usage reduction was not statistically significant for any of the heating-class segments during CPP events compared to reference days.

Table 27: Change in Daily Electricity Usage (kWh/day) by Cohort during CPP Events for Residential CPP Participants

Parameters	Cohort 1	Cohort 2	Cohort 3	Cohort 4	All
Avg. Usage Reduction (kWh/day)[a]	1.6 ± 4.0	3.1 ± 6.7	1.6 ± 2.9	1.6 ± 1.5	1.7 ± 1.3
Avg. Usage – Residential CPP Participants, Pre-Pilot (kWh/day)	61	71	55	52	54
Relative Avg. Usage Reduction (%)[a]	2.7%	4.3%	2.9%	3.1%	3.1%
Significance (p_Value≤0.05)	X	X	X	✓	✓

[a] Positive values represent 'Usage Reduction' and Negative values represent 'Usage Increase.'

The results of the second analysis are summarized in Table 28 and show changes in daily electricity usage level for cohorts 1 to 4 and all cohorts combined during non-holiday weekdays and holiday weekends in Winter as well as non-Winter days. All cohorts significantly reduced their daily usage during non-holiday weekdays in Winter. All cohorts exhibit load reductions during weekends

holidays in Winter, although the load reduction in cohort 3 is not statistically significant. Due to the lack of data for non-Winter days in cohort 4, evaluation of the daily usage reduction during non-Winter days was not completed. For all cohorts of CPP participants combined, the annually aggregated usage level reductions are estimated at 0.973 ±0.24 kWh per day, which add up to 355 kWh per year on average and are statistically significant.

Table 28: Change in Daily Electricity Usage (kWh/day) by Cohort for Residential CPP Participants

Parameters	Cohort 1	Cohort 2	Cohort 3	Cohort 4	All
Winter, Non-Holiday Weekdays					
Avg. Usage Reduction (kWh/day)[a]	3.0 ± 1.4	3.1 ± 2.0	1.0 ± 0.9	1.1 ± 0.5	1.2 ± 0.4
Avg. Usage – Residential CPP Participants, Pre-Pilot (kWh/day)	50.7	60.5	44.0	43.5	44.5
Relative Usage Reduction (%)[a]	6.0%	5.1%	2.3%	2.5%	2.7%
Significance (p_Value≤0.05)	✓	✓	✓	✓	✓
Winter, Weekends / Holidays					
Avg. Usage Reduction (kWh/day)[a]	2.3 ± 1.7	4.0 ± 2.5	0.9 ± 1.1	0.9 ± 0.6	1.0 ± 0.5
Avg. Usage – Residential CPP Participants, Pre-Pilot (kWh/day)	51.0	62.0	45.8	44.6	45.7
Relative Usage Reduction (%)[a]	4.6%	6.5%	1.8%	2.1%	2.3%
Significance (p_Value≤0.05)	✓	✓	X	✓	✓
Non-Winter Days					
Avg. Usage Reduction (kWh/day)[a]	1.9 ± 0.5	-0.3 ± 1.0	-0.1 ± 0.3	n/a	0.5 ± 0.3
Avg. Usage – Residential CPP Participants, Pre-Pilot (kWh/day)	28.4	30.2	25.6		26.7
Relative Usage Reduction (%)[a]	6.8%	-1.0%	-0.5%		2.0%
Significance (p_Value≤0.05)	✓	X	X		✓

[a] Positive values represent 'Usage Reduction' and Negative values represent 'Usage Increase.'

Table 29 presents changes in daily electricity usage level by space heating for all cohorts of residential CPP participants during pilot period compared to pre-pilot period. During non-holiday weekdays in Winter, CPP participants with electrified space heating exhibited a statistically significant increase in daily usage level by 13%, corresponding to a daily usage increase of 3.84 kWh. In contrast, de-electrified and steady electric participants demonstrated significant daily usage reductions of 1.31 kWh and 2.01 kWh, respectively. Steady non-electric participants exhibit statistically insignificant changes in daily electricity usage level during non-holiday weekdays.

Table 29: Change in Daily Electricity Usage Level by Space Heating Type for All Cohorts of Residential CPP Participants

Parameters	De-Electrified	Electrified	Steady Electric	Steady Non-Electric
Winter, Non-Holiday Weekdays				
Avg. Usage Reduction (kWh/day)[a]	1.31 ± 1.08	-3.84 ± 0.81	2.02 ± 0.45	0.15 ± 0.33
Avg. Usage – Residential CPP Participants, Pre-Pilot (kWh/day)	42.0	29.6	55.6	18.7
Relative Avg. Usage Reduction (%)[a]	3.1%	-13.0%	3.6%	0.8%
Significance (p_Value≤0.05)	✓	✓	✓	X
Winter, Weekends / Holidays				
Avg. Usage Reduction (kWh/day)[a]	0.71 ± 1.42	-4.39 ± 1.04	1.99 ± 0.56	-0.09 ± 0.4
Avg. Usage – Residential CPP Participants, Pre-Pilot (kWh/day)	42.8	30.8	56.9	19.5
Relative Avg. Usage Reduction (%)[a]	1.7%	-14.3%	3.5%	-0.5%
Significance (p_Value≤0.05)	X	✓	✓	X
Non-Winter Days				
Avg. Usage Reduction (kWh/day)[a]	0.14 ± 1.72	-0.97± 0.67	0.50 ± 0.34	0.41 ± 0.49
Avg. Usage – Residential CPP Participants, Pre-Pilot (kWh/day)	26.7	21.7	29.7	18.9
Relative Avg. Usage Reduction (%)[a]	0.5%	-4.4%	1.7%	2.1%
Significance (p_Value≤0.05)	X	✓	✓	X

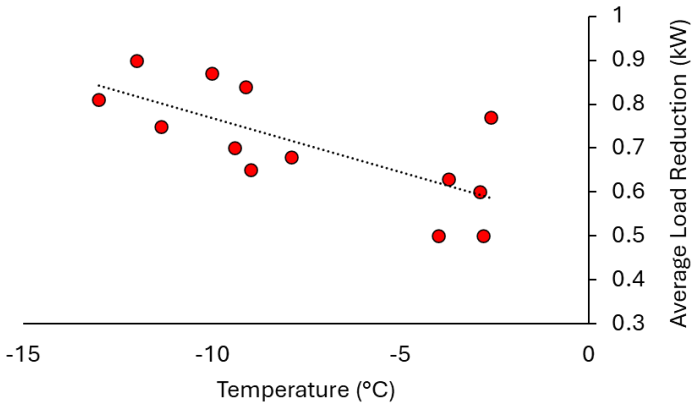
[a] Positive values represent 'Usage Reduction' and *Negative* values represent 'Usage Increase'.

As seen in Table 29, during weekends / holidays in Winter, CPP customers with electrified heating systems increased their daily usage levels by 14.3%, corresponding to 4.39 kWh, which is statistically significant. In contrast, participants with steady electric heating systems achieved daily usage reductions of 3.5%, corresponding to statistically significant electricity usage reduction of 1.99 kWh during weekends / holidays. CPP customers with de-electrified or steady non-electric heating systems demonstrated insignificant changes in daily usage level during weekends / holidays in Winter.

4.1.5 Effect of Weather (Temperature) on Load Reduction

The DiD analysis reveals that the average load reduction is increased by 0.019 kW (± 0.003 kW) per 1 °C decrease in outdoor temperature, implying that CPP customers increase load reduction when the weather becomes colder. Figure 30 illustrates the correlation between average load reduction (kW) and average outdoor temperature during CPP event days, where the upward trend with respect to colder temperature indicates an increasing load reduction when the outdoor temperature decreases.

Figure 30: The Correlation of Load Reduction by Residential CPP Participants with Outdoor Temperature



4.1.6 Effect of Consecutive CPP Events on Load Reduction

During Phase 4, like Phase 3, there was only one instance of two consecutive CPP events, which occurred when events 5 and 6 took place on December 23, 2024. The second of these consecutive events (event 6) led to a slightly higher load reduction, but not statistically different, compared to its preceding event (event 5). This suggests that being preceded by another CPP event did not negatively affect the load reduction by CPP residential customers during this event. However, because Phase 4 includes only a single occurrence of consecutive events, the available data is insufficient to draw broader conclusions the overall impact of consecutive CPP events. The individual event load impacts are displayed in Figure 23.

4.2 Economic Impacts

This section presents and discusses the impact of residential CPP tariffs on the electricity bill as well as price elasticity.

4.2.1 Change in Electricity Bills

Table 30 summarizes the applicable tariffs used for residential CPP impact on billing. Tariff details can be found in Attachment I: Riders and Tariff Structure.

Table 30: Tariffs Used for Analyzing Residential CPP Impact on Electricity Bill

Customer Type and Period	Applicable Tariff
Control, Reference Day	Domestic Standard Tariff
Control, during Pilot	Domestic Standard Tariff
Treatment, Reference Day	Domestic Standard Tariff
Treatment, during Pilot	Domestic CPP Tariff

Table 31 presents the bill impact for residential CPP, where participants exhibit an overall annual average bill saving of $0.57 per day, corresponding to 8.6% of average annual bill. This amount of

annual bill saving is statistically significant. The residential CPP participants achieved an average bill saving of $0.75 per day during non-Winter days, corresponding to 15.0% of average non-Winter bill. The non-Winter days savings are primarily due to a reduced rate per kWh during the non-Winter days (14.222¢/kWh under CPP Tariff compared to 16.931¢/kWh for domestic tariffs). Furthermore, the CPP participants achieved an overall bill saving of $0.37 per day during Winter. Also, the participants experienced the highest bill saving of $0.80 during weekends/holidays in Winter. Notably, participants experienced bill savings of $0.14 per day during non-holiday/weekdays when the majority of CPP events occurred. This lower bill saving is attributed to the fact that tariffs during CPP peak hours (169.31 ¢/kWh) are approximately twelve times higher than the Tariff during non-event hours (14.222 ¢/kWh).

Table 31: Change in Daily Electricity Bill for All Cohorts of Residential CPP Participants

Parameters	Winter Non-Holiday Weekdays	Winter Holiday/ Weekends	Winter Overall	Non-Winter Days	Annual Average
Avg. Bill Savings ($/day)[a]	0.14 ± 0.01	0.80 ± 0.02	0.37 ± 0.01	0.75± 0.01	0.57 ± 0.01
Avg. Bill – Residential CPP Participants, Pre-Pilot ($/day)	8.4	8.6	8.5	5.0	6.5
Relative Avg. Bill Savings (%)[a]	1.7%	9.3%	4.4%	15.0%	8.6%
Significance (p_Value≤0.05)	✓	✓	✓	✓	✓

[a] Positive values represent 'Bill Savings' and *Negative* values represent 'Bill Increase.'

The analysis reveals that the type of space heating has a significant effect on the bill savings for the CPP participants. The steady electric participants achieved the highest bill savings compared to steady non-electric. While CPP participants who switched heating types show a change in electric costs, this analysis does not account for additional fuel costs or fuel savings for non-electric heating sources they may have incurred. All space heating classes experienced the most bill savings during non-Winter days, among which the participants with steady electric heating systems achieved the highest bill savings of $0.86 per day. Overall, except for electrified CPP participants, other space heating types achieved statistically significant annual bill savings ranging from $153 to $248 per year. While electrified customers achieved a bill savings of $101 during non-Winter season, they did not experience statistically significant annual bill savings.

Table 32: Change in Daily Electricity Bill by Space Heating Type for All Cohorts of Residential CPP Participants

Parameters	De-Electrified	Electrified	Steady Electric	Steady Non-Electric
Winter				
Avg. Bill Savings ($/day)[a]	0.36 ± 0.04	-0.47 ± 0.03	0.56 ± 0.02	0.14 ± 0.01
Avg. Bill – Residential CPP, Pre-Pilot ($/day)	6.3	8.0	10.3	3.4
Relative Avg. Bill Savings (%)[a]	5.8%	-5.9%	5.4%	4.1%
Significance (p_Value≤0.05)	✓	✓	✓	✓
Non-Winter				
Avg. Bill Savings ($/day)[a]	0.70 ±0.04	0.47 ± 0.02	0.86 ± 0.01	0.57 ± 0.02
Avg. Bill – Residential CPP, Pre-Pilot ($/day)	4.4	3.7	4.7	3.0
Relative Avg. Bill Savings (%)[a]	15.9%	12.5%	18.3%	18.8%
Significance (p_Value≤0.05)	✓	✓	✓	✓
Annual				
Avg. Bill Savings ($/day)[a]	0.44 ± 0.03	0.02 ± 0.03	0.68 ± 0.01	0.42 ± 0.04
Avg. Bill – Residential CPP, Pre-Pilot ($/day)	5.4	5.4	7.3	3.3
Relative Avg. Bill Savings (%)[a]	8.1%	0.3%	9.4%	12.7%
Significance (p_Value≤0.05)	✓	X	✓	✓

[a] Positive values represent 'Bill Savings' and *Negative* values represent 'Bill Increase.'

4.2.2 Price Elasticity

Price elasticity was evaluated to measure residential CPP participants' responsivity to electricity prices during Phase 4. Specifically, NS Power evaluated Daily Price Elasticity during Winter season and annual overall, as well as the Inter-period Substitution Price Elasticity during Winter season.

For clarification, Daily Price Elasticity reflects the change in overall daily electricity usage caused by changes in the average daily price ($) per kWh. It is expressed as the percent (%) change in the average electricity usage associated with a 1% increase in the daily average energy price. Inter-period Substitution Price elasticity reflects the participants' ability to substitute more expensive electricity usage during CPP events with less expensive off-peak loads, and estimates changes in load shapes caused by a change in the peak-to-off-peak price ratio. It is expressed as the percent (%) change in the ratio of peak-to-off-peak average load associated with a 1% increase in the peak-to-off-peak price ratio.

The analysis reveals Daily Price Elasticity of -0.2 (± 0.06) during Winter season, indicating that for 1% increase in the average daily price per kWh, the average daily electricity usage decreases by 0.2% during Winter. Furthermore, the inter-period substitution elasticity is estimated at -0.19 (± 0.004), indicating that a 1% increase in the ratio of peak-to-off-peak rates can lead to a decrease of 0.19% in the peak-to-off-peak load ratio by the residential CPP customers, which is statistically significant.

5 Commercial TOU Tariff Impacts

This section presents and discusses the estimated load and economic impacts of the commercial TOU program. The goal of the commercial TOU pilot is to encourage customers to shift their electricity usage from peak periods to off-peak periods when system utilization is typically lower. This is done by presenting customers with option to lower their energy bills if they participate in load shifting. The price differential is derived from system savings created in the near-term in the form of reduced fuel and purchased power costs, and over the longer-term in the form of avoided generation, transmission and distribution infrastructure costs.

Commercial TOU customer sample size for Phase 4 is currently at 50 participants, most of which enrolled in cohorts 1 – 3 (n = 46) as cohort 4 experienced relatively small enrolment (n=4). A summary of Commercial TOU sample size for the regression is summarized in Table 33.

Table 33: Summary of Commercial TOU Sample Size[10]

Parameter	Cohort 1	Cohort 2	Cohort 3	Cohort 4	All
Sample Size	19	15	12	4	50
Rate Class					
Small General	9	13	6	4	32
General	10	2	6	0	18
Region					
HRM	12	3	6	3	24
Rest of Nova Scotia	7	12	6	1	26

5.1 Load Impacts

This section presents and discusses the electrical load impact from the commercial TOU pilot.

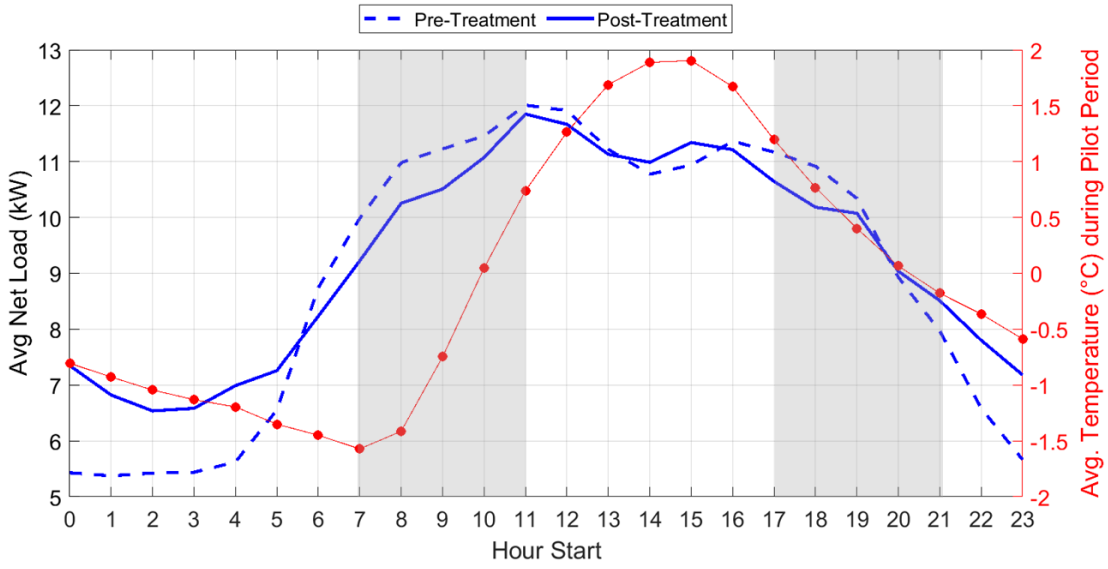
5.1.1 Change in Load during Peak Periods

Figure 31 illustrates the load profiles for commercial TOU participants during the pre-pilot and pilot periods, along with the corresponding variation in outdoor temperature during the pilot period.

Commercial TOU participants exhibit an overall reduction in electricity load during TOU peak hours compared to the pre-pilot period. Notably, during pilot period commercial TOU participants experience a pronounced increase in their load relative to pre-pilot period overnight following evening peak hours and prior to morning peak hours (9:00 PM – 5:00 AM).

[10] Participation in this table differs from the participation summary found in Table 5 as some participants are removed due to not meeting AMI data criteria necessary for the regression analysis. Refer to the seasonal load ratio analysis in equation (13) and cleaning steps in Table 69.

Figure 31: The Hourly-Averaged Load Shapes during Winter Non-Holiday Weekdays for Commercial TOU Participants during Pilot Period and Pre-Pilot Period, and the Variation of Average Outdoor Temperature during Pilot Period with Time (Hour) Corresponding to Commercial TOU Post-Treatment Participants (Highlighted Areas Represent Morning and Evening Peak Hours)



On average, the analysis reveals that commercial TOU participants exhibit an overall peak reduction of 0.8 kW in electricity load, with average load reductions of 6.4%, 8.6%, and 7.4% observed during the morning and evening peaks, and overall for all peak periods, respectively. This estimated effect of commercial TOU is consistent with the difference in load shape during peak hours between pre-pilot and pilot period, as shown in Figure 31.

Table 34 summarizes the results of the Mixed-Effects regression analysis for the morning and evening as well as the overall load impact. Estimated impacts are presented alongside MoE at the 90% confidence level. As shown in Table 34, the estimated impacts of the commercial TOU pilot on average load in overall and during morning and evening peak periods are statistically significant.

Table 34: Change in Load during TOU Peaks for Commercial TOU Participants

Parameters	Morning Peak	Evening Peak	All Peak Hours (Overall)
Avg. Load Reduction (kW)[a]	0.7 ± 0.2	0.9 ± 0.2	0.8 ± 0.1
Avg. Load – Commercial TOU Participants, Pre-Pilot (kW)	10.9	10.3	10.6
Relative Avg. Load Reduction (%)[a]	6.4%	8.6%	7.5%
Significance (p_Value≤0.05)	✓	✓	✓

[a] Positive values represent 'Load Reduction' and Negative values represent 'Load Increase.'

Change in Load during Peak Events by Region

Table 35 presents the average load reduction (kW) by region (Halifax area versus the rest of Nova Scotia) for commercial TOU participants during morning, evening, and all peak hours. Commercial

TOU participants located in the Halifax area exhibit statistically significant load reductions during both morning and evening peak hours with an overall load reduction of 1.4 kW, corresponding to 12% relative load reduction. Likewise, commercial TOU participants in the rest of Nova Scotia exhibit a statistically significant overall load reduction of 0.2 kW across all morning and evening peak hours, although only load reduction during evening peak hours and overall is statistically significant.

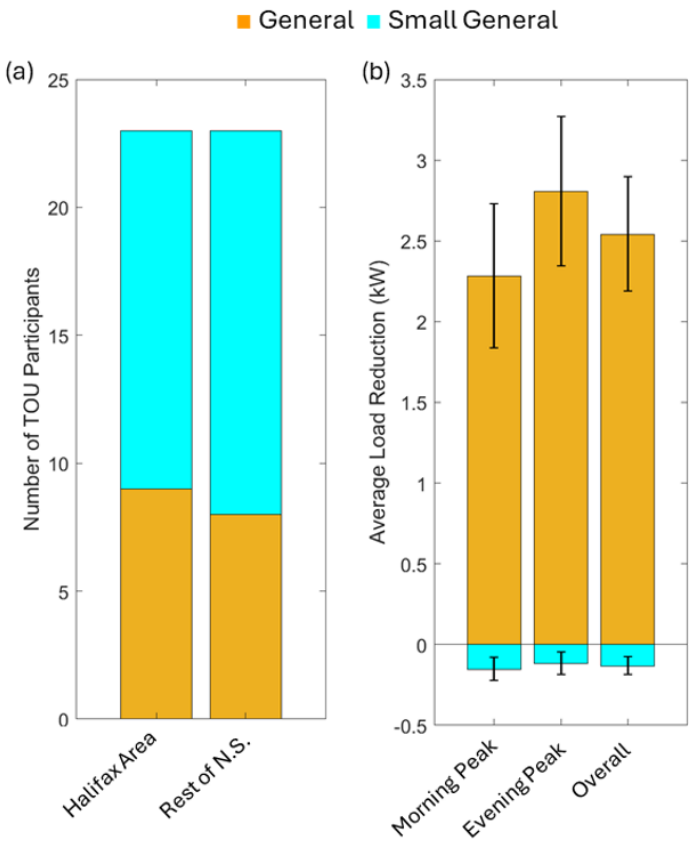
Table 35: Change in Load during TOU Peak Hours by Region for Commercial TOU Participants

Parameters	Halifax Area			Rest of Nova Scotia		
	Morning Peaks	Evening Peaks	All Peak Hours	Morning Peaks	Evening Peaks	All Peak Hours
Avg. Load Reduction (kW)[a]	1.22 ± 0.29	1.49 ± 0.31	1.38 ± 0.20	0.16 ± 0.17	0.24± 0.18	0.20 ± 0.15
Avg. Load – Commercial TOU Participants, Pre-Pilot (kW)	11.9	11.1	11.5	9.9	9.9	9.9
Relative Avg. Load Reduction (%)[a]	10.3%	13.7%	12.0%	1.6%	2.5%	2.1%
Significance (p_Value≤0.05)	✓	✓	✓	X	✓	✓

[a] Positive values represent 'Load Reduction' and Negative values represent 'Load Increase.'

Figure 32a illustrates the distribution of General and Small General commercial TOU participants in the Halifax area compared to the rest of Nova Scotia.

Figure 32: (a) Distribution of Number of General and Small General TOU Participants in Halifax Area and the Rest of Nova Scotia, and (b) the Average Load Reduction (kW) for General and Small General Business Types

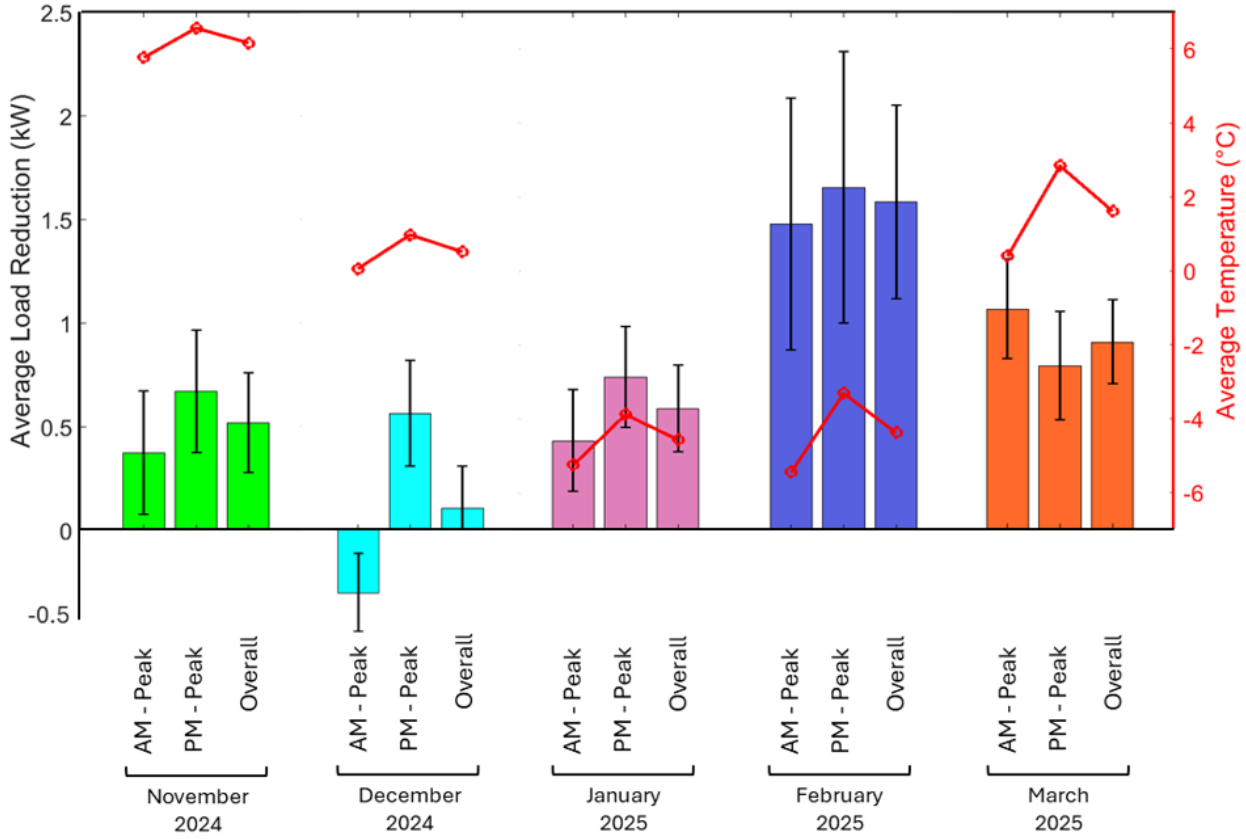


Notably, as shown in Figure 32b, General commercial TOU participants exhibit significant load reductions during both morning and evening peak periods, with an average overall reduction of approximately 2.6 kW. In contrast, Small General TOU participants show load increases during peak hours, with an average increase of approximately 0.22 kW, which is statistically significant although small in magnitude.

Change in Load by Month during Peak Periods

Figure 33 illustrates the impact of commercial TOU in terms of average load reduction (kW), together with the average outdoor temperature (°C) during peak hours by month over the Winter period from November 2024 to March 2025. Except for the morning peak period in December 2024 – which shows a statistically significant load increase – commercial TOU participants demonstrated significant load reductions during both morning and evening peak hours across all Winter months. Notably, in January 2025, when temperatures reached their lowest range (approximately −4 °C to −5.3 °C), participants achieved significant reductions during both morning and evening peak periods. The largest overall load reduction, approximately 1.6 kW, occurred in February 2025, when outdoor temperatures ranged between −3.3 °C and −5.4 °C.

Figure 33: Average Load Reduction (kW) and Temperature Variation during Commercial TOU Peak Periods in Winter for the Months of November, December, January, February, and March



5.1.2 Snapback Effect

NS Power evaluated the snapback effect based on the same method that was applied for load reduction calculation, but specifically for the four hours following the morning and evening peak hours. As summarized in Table 36, commercial TOU participants exhibited a statistically significant load reduction of 0.51 kW during morning snapback hours. In contrast, during evening snapback hours they demonstrated a load increase of 0.9 kW, corresponding to a relative load increase of 13.3%. Although commercial TOU customers showed an overall relative load increase of 1.2% across all snapback periods, this effect was not statistically significant.

Table 36: Snapback Effect for Commercial TOU Participants

Parameters	Avg. Load Reduction [a] (kW)	Relative Avg. Load Reduction [a] (%)	Significance (p_Value≤0.05)
Morning Snapback	0.51 ± 0.19	4.4%	✓
Evening Snapback	-0.90 ± 0.17	-13.3%	✓
Overall Snapback	-0.11 ± 0.17	-1.2%	X

[a] Positive values represent 'Load Reduction' and Negative values represent 'Load Increase.'

5.1.3 Change in Load during Highest ANL Hours

Figure 34 depicts the distribution of Top 20, 50 and 88 highest ANL hours for commercial TOU participants during off-peak, morning peak, evening peak, Weekends and Holidays. As seen in Figure 34a-c, ANL hours occurred disproportionally on weekdays (85% – 92%), exceeding the expected baseline of 5/7 (71%). In addition, more than 70% of the highest ANL hours coincide with the morning and evening peak periods for all distributions of top ANL hours (i.e. 20, 50 and 88). Note that Figure 34 is identical to Figure 20 (Domestic TOU) as the tariffs have the same peak periods.

Figure 34: Distribution of Top 20, Top 50 and Top 88 ANL Hours by Day Type (Weekday / Weekend) and Commercial TOU Period

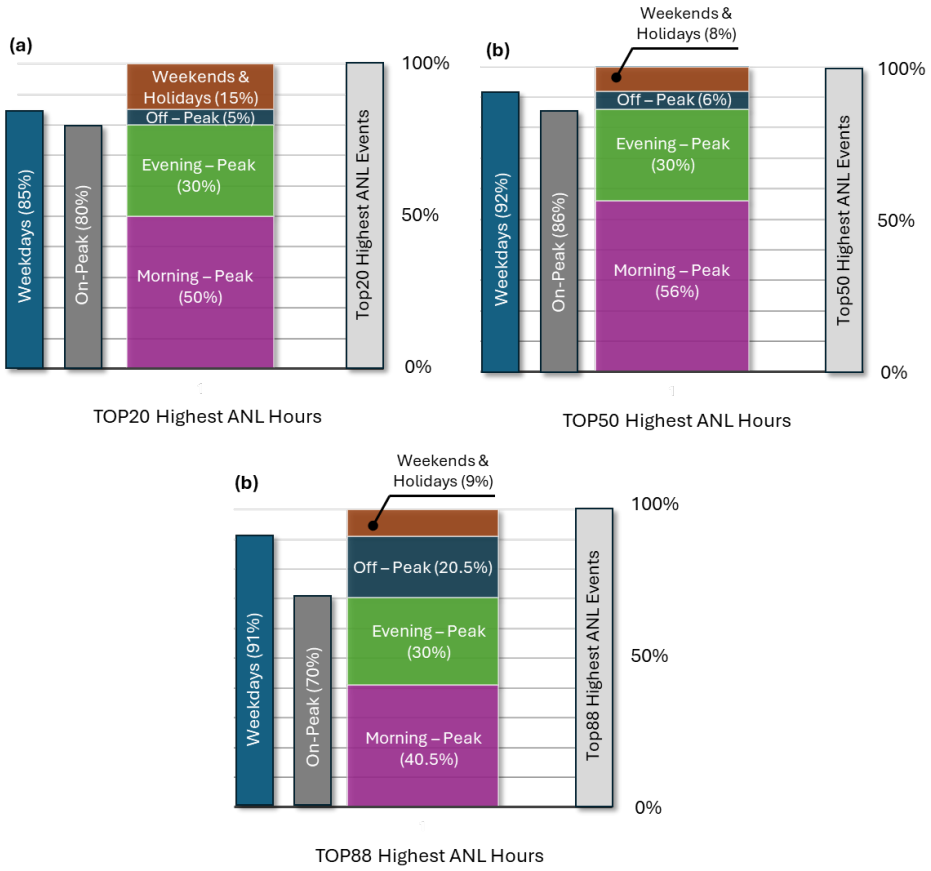


Table 37 summarizes the estimated changes in load during the highest ANL hours overall, as well as during ANL hours that coincide with TOU peak periods. Results indicate that the load increase or reduction by commercial TOU participants was not statistically significant during the top 20, 50, and 88 highest ANL hours. When focusing specifically on ANL hours that coincide with TOU peak periods, the commercial TOU participants exhibit insignificant load increases or decreases during the top 20, 50 and 88 ANL hours compared to the corresponding highest ANL hours overall.

Table 37: Change in Load (kW) during Highest Winter ANL Hours for Commercial TOU Participants

Parameters	Highest ANL Hours			ANL Hours Coincide TOU Peak Periods		
	Top20	Top 50	Top88	Top20	Top 50	Top88
Avg. Load Reduction (kW)[a]	0.06 ± 0.85	0.34 ± 0.50	-0.15 ± 0.44	-0.12 ± 0.84	0.20 ± 0.48	0.10 ± 0.40
Avg. Load Participants, Pre-Pilot (kW)	10.2	9.8	9.0	5.8	7.3	8.2
Relative Avg. Load Reduction (%)[a]	0.5%	3.5%	-1.6%	-2.0%	2.7%	1.2%
Significance (p_Value≤0.05)	X	X	X	X	X	X

[a] Positive values represent 'Load Reduction' and Negative values represent 'Load Increase'

5.1.4 Change in Usage

Changes in daily electricity usage were estimated by applying the same method which was used for estimating hourly load-impact, to daily electricity usage. Table 38 presents the estimated changes in daily electricity usage (kWh/day) for commercial TOU participants.

Table 38: Change in Daily Electricity Usage (kWh/day) for Commercial TOU Participants

Parameters	Annual Average	Winter Overall	Winter – Non-Holiday Weekdays	Winter – Holiday Weekends	Non-Winter
Avg. Usage Reduction (kWh/day)[a]	-15.4 ± 3.9	-9.4 ± 4.0	-3.9 ± 5.1	-19.4 ± 6.5	-22.2 ± 5.7
Avg. Usage – Commercial TOU Participants, Pre-Pilot (kWh/day)	206	194	202	178	216
Relative Usage Reduction (%)[a]	-7.5%	-4.8%	-1.9%	-10.9%	-10.3%
Significance (p_Value≤0.05)	✓	✓	X	✓	✓

[a] Positive and negative values represent 'Usage Reduction' and 'Usage Increase,' respectively.

As shown in Table 38, Commercial TOU participants exhibit a statistically significant increase in daily electricity usage of approximately 15.9 kWh/day on annual average and 19.4 kWh/day during Winter non-holiday weekdays, corresponding to 7.5% and 10.9% increases in daily usage, respectively. In contrast, the commercial TOU participants exhibit a statistically insignificant increase in daily electricity usage during non-holiday weekdays in Winter.

5.2 Economic Impacts

This section presents and discusses the impact of commercial TOU tariffs on the electricity bill as well as price elasticity.

5.2.1 Change in Electricity Bills

The bill impact analysis for the commercial TOU uses the same method that was used for estimating the commercial TOU load impact analysis. In the bill impact analysis, applicable tariffs applied in accordance with the customer type and pilot period, as summarized in Table 39. Note details on these tariffs are included in Attachment I: Riders and Tariff Structure.

Table 39: Tariffs Used for Evaluating the Impact of Commercial TOU on Electricity Bill

Customer Type	Period	Applicable Tariff
Treatment – General	Pre-Pilot	General Tariff – Rate Code 11
Treatment – General	Pilot	General TOU Tariff – Rate Code 83
Treatment – Small General	Pre-Pilot	Small General Tariff – Rate Code 10
Treatment – Small General	Pilot	Small General TOU Tariff – Rate Code 82

Table 40 presents the estimated average changes in daily bill for all cohorts of commercial TOU participants over the Winter season and annual average in Phase 4. The commercial TOU customers experienced an average Bill increase of approximately 11.9 $/day and 1.1 $/day across the Winter and annually, respectively. The increase in daily electricity bill ($/day) is consistent with the daily electricity usage increase during the Winter and annually, as shown in Figure 35 and Table 40 for commercial TOU customers.

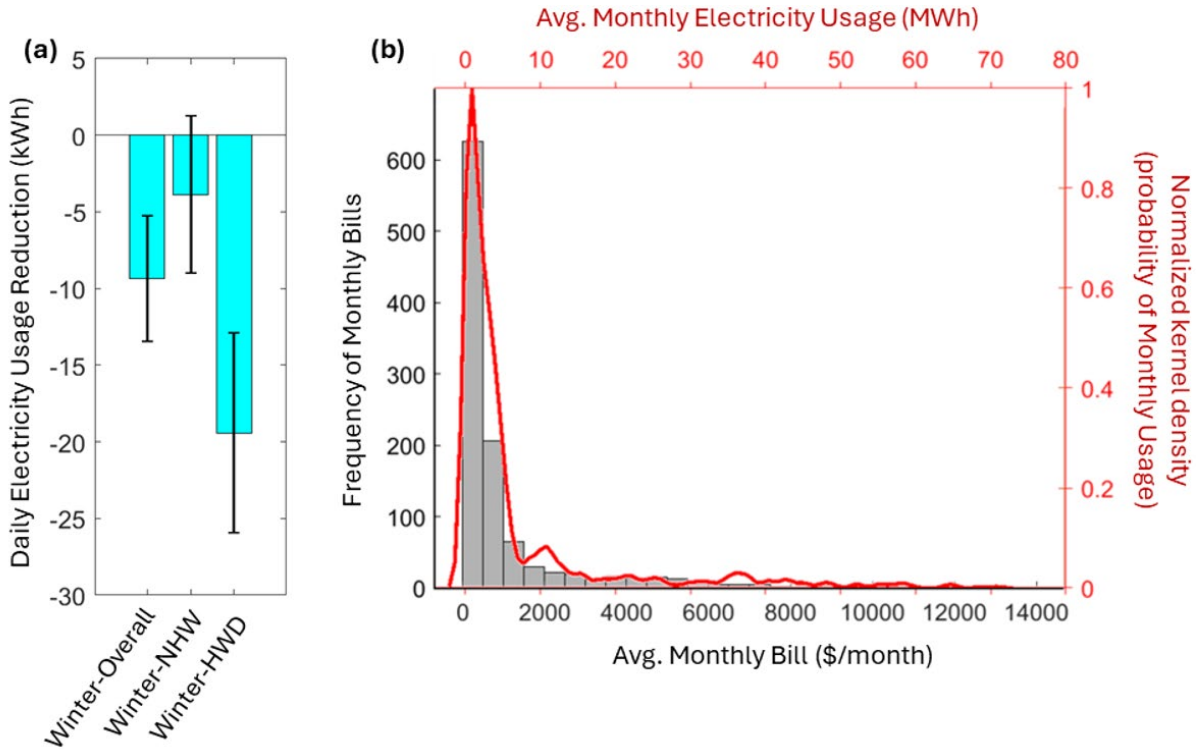
Table 40: Change in Daily Electricity Bill for Commercial TOU Participants

Parameters	Winter	Non-Winter	Annual Overall
Avg. Bill Savings ($/day)[a]	-11.9 ± 3.4	6.2 ± 3.1	-1.1 ± 3.1
Avg. Bill, Commercial TOU Participants, Pre-Pilot ($/day)	36.7	37.4	37.0
Relative Avg. Bill Savings (%)[a]	-32%	16.7%	-3.1%
Significance (p_Value≤0.05)	✓	✓	X

[a] Positive values represent 'Bill Savings' and Negative values represent 'Bill Increase.'

Interestingly, regardless that commercial customers demonstrated a significant increase in energy consumption during the non-Winter (Table 38), their average daily bill did not demonstrate statistically significant change as shown in Table 40.

Figure 35: (a) Average Reduction in Daily Electricity Usage (kWh) by Commercial TOU Participants, Where the Negative Reduction Represents an Increase in Usage. (b) Distribution of Average Monthly Electricity Bills ($/Month) and Average Monthly Electricity Usage (MWh) for Commercial TOU Customers



It should be noted that most commercial TOU participants in Phase 4 belong to the Small General business segment (32 customers), compared to 18 customers in the General segment, with no General rate class recruitment in Cohort 4 (Table 33). Figure 35b presents the distribution of average monthly electricity bills ($/month) and average monthly electricity usage (MWh) for commercial TOU customers used for the economic impact analysis. As illustrated in Figure 35b, the highest density of customers falls within the $600–$1,500 monthly bill range, which corresponds to the most frequent monthly electricity usage range of approximately 0.8–6 MWh. This distribution indicates that the economic impact results are primarily driven by the commercial TOU customers with small-to-medium electricity consumption, which is consistent with the predominance of Small General customers in the Phase 4 TOU sample.

5.2.2 Price Elasticity

Daily Price Elasticity reflects the change in overall daily electricity usage caused by changes in the average daily price ($) per kWh. It is expressed as the percent (%) change in the average electricity usage associated with a 1% increase in the daily average energy price. Inter-period Substitution Price elasticity reflects the participants' ability to substitute more expensive peak loads with less expensive off-peak loads and estimates changes in load shapes caused by a change in the peak-to-off-peak price ratio for all Winter days. It is expressed as the percent (%) change in the ratio of peak-to-off-peak average load associated with a 1% increase in the peak-to-off-peak price ratio.

Chapter 5: Commercial TOU Tariff Impacts

The results demonstrated a Daily Price Elasticity of 0.12 (± 0.17) during Winter season and -0.21 (± 0.08) annual overall. The daily price elasticity during Winter season may imply that for 1% increase in the average daily price per kWh, the average daily electricity usage is increased by 0.13% during the Winter season; however, it is not statistically significant. In contrast, the annual daily price elasticity of -0.21 is statistically significant, suggesting that a 1% increase in the average daily price per kWh leads to an average reduction of approximately 0.21% in electricity usage over the year. Additionally, the inter-period substitution elasticity is estimated at -0.065 (± 0.02), which is statistically significant. It indicates that during Winter season a 1% increase peak-to-off-peak rate ratio results in 0.065% reduction in the peak-to-off-peak load ratio, reflecting load shifting from peak to off-peak periods.

6 Commercial CPP Tariff Impacts

This section presents and discusses the estimated load and economic impacts of the commercial CPP program. The goal of the commercial CPP pilot is to encourage customers to shift their electricity usage from peak events to off-peak periods when system utilization is lower. This is done by presenting customers with option to lower their energy bills if they participate in load shifting. The price differential is derived from system savings created in the near-term in the form of reduced fuel and purchased power costs, and over the longer-term in the form of avoided generation, transmission and distribution infrastructure costs.

This section presents and discusses the estimated load and economic impacts of the commercial CPP program, based on a Mixed-Effects modeling semi-DiD approach. The CPP Tariff impact analysis was conducted for CPP events called during Phase 4 from November 01, 2024, to March 31, 2025. Table 41 presents the CPP event dates along with the Starting and Ending times, average outdoor temperature, and the weekday status.

Table 41: List of CPP Events with Corresponding Starting/Ending Times, Average Outdoor Temperature, and Weekday Status

Event Number	Event Date	Event Start Time (Hour)	Event End Time (Hour)	Average Outdoor Temperature (°C)	Weekday Status
1	2024-12-04	17:00	21:00	-3.6	NHW[a]
2	2024-12-15	17:00	21:00	-2.5	Weekend
3	2024-12-20	7:00	11:00	-2.9	NHW
4	2024-12-22	17:00	21:00	-9.5	Weekend
5	2024-12-23	7:00	11:00	-9.0	NHW
6	2024-12-23	17:00	21:00	-9.0	NHW
7	2025-01-21	17:00	21:00	-9.1	NHW
8	2025-01-22	7:00	11:00	-13.1	NHW
9	2025-02-02	17:00	21:00	-9.9	Weekend
10	2025-02-05	17:00	21:00	-12.2	NHW
11	2025-02-06	7:00	11:00	-11.0	NHW
12	2025-03-04	7:00	11:00	-7.8	NHW
13	2025-03-10	7:00	11:00	-2.5	NHW
14	2025-03-11	7:00	11:00	-3.9	NHW

[a]NHW: Non-Holiday Weekdays

As shown in Table 41, three CPP events (Dec. 15, 2024, Dec. 22, 2024, and Feb. 02, 2025) took place during weekends. The morning and evening consecutive events occurred on December 23, 2024. The CPP events include seven morning and seven evening events, where the coldest (-13.1 °C) event day took place on January 22, 2025.

Commercial CPP customer participation for Phase 4 is currently at 28 participants. Contrary to commercial TOU, most of the enrolment for commercial CPP occurred in Cohort 4. A summary of Commercial CPP sample size used in the analysis is summarized in Table 42.

Table 42: Summary of Commercial CPP Sample Size[11]

Parameter	Cohort 1	Cohort 2	Cohort 3	Cohort 4	All
Sample Size	4	1	3	20	28
Rate Class					
Small General	2	0	1	8	11
General	2	1	2	12	17
Region					
HRM	2	0	3	16	21
Rest of Nova Scotia	2	1	0	4	7

6.1 Load Impacts

This section presents and discusses the electrical load impact from the commercial CPP pilot.

6.1.1 Change in Load during Peak Events

Table 43 summarizes the results of the analysis for morning and evening CPP events for all cohorts of commercial CPP participants in Phase 4, where the average load reduction values are presented along with their MoE at 90% confidence level. The commercial CPP participants demonstrated significant average load reductions during morning and evening CPP events with a relative load reduction of 9.6% overall for all events.

Table 43: Change in Load during CPP Events for Commercial CPP Participants

Parameters	Morning Events	Evening Events	All Events
Avg. Load Reduction (kW)[a]	7.9 ± 2.9	5.1 ± 2.7	6.3 ± 2.3
Avg. Load – Commercial CPP Participants, Pre-Pilot (kW)	69.5	64.7	65.7
Relative Avg. Load Reduction (%)[a]	11.4%	7.9%	9.6%
Significance (p_Value≤0.05)	✓	✓	✓

[a] Positive values represent 'Load Reduction' and Negative values represent 'Load Increase.'

Figure 36 illustrates the daily load profile for commercial CPP participants during pilot period on CPP days compared to reference days with morning events only, evening events only, and double events, as well as for all event days. The CPP participants exhibit load shift during morning events (Figure 36a, c) and evening events (Figure 36b, c), compared to reference days. In overall, the CPP participants demonstrated load reduction during CPP events, indicating shifting their load compared to their load during reference days (Figure 36d).

[11] Participation in this table differs from the participation summary found in Table 5 as some participants are removed due to not meeting AMI data criteria necessary for the regression analysis. Refer to the seasonal load ratio analysis in equation (13) and cleaning steps in Table 69.

Figure 36: Load Shapes for Commercial CPP Participants on Event Days (a) with Morning Only Events, (b) with Evening Only Events, (c) with Both Morning and Evening Events, and (d) for All Event Days

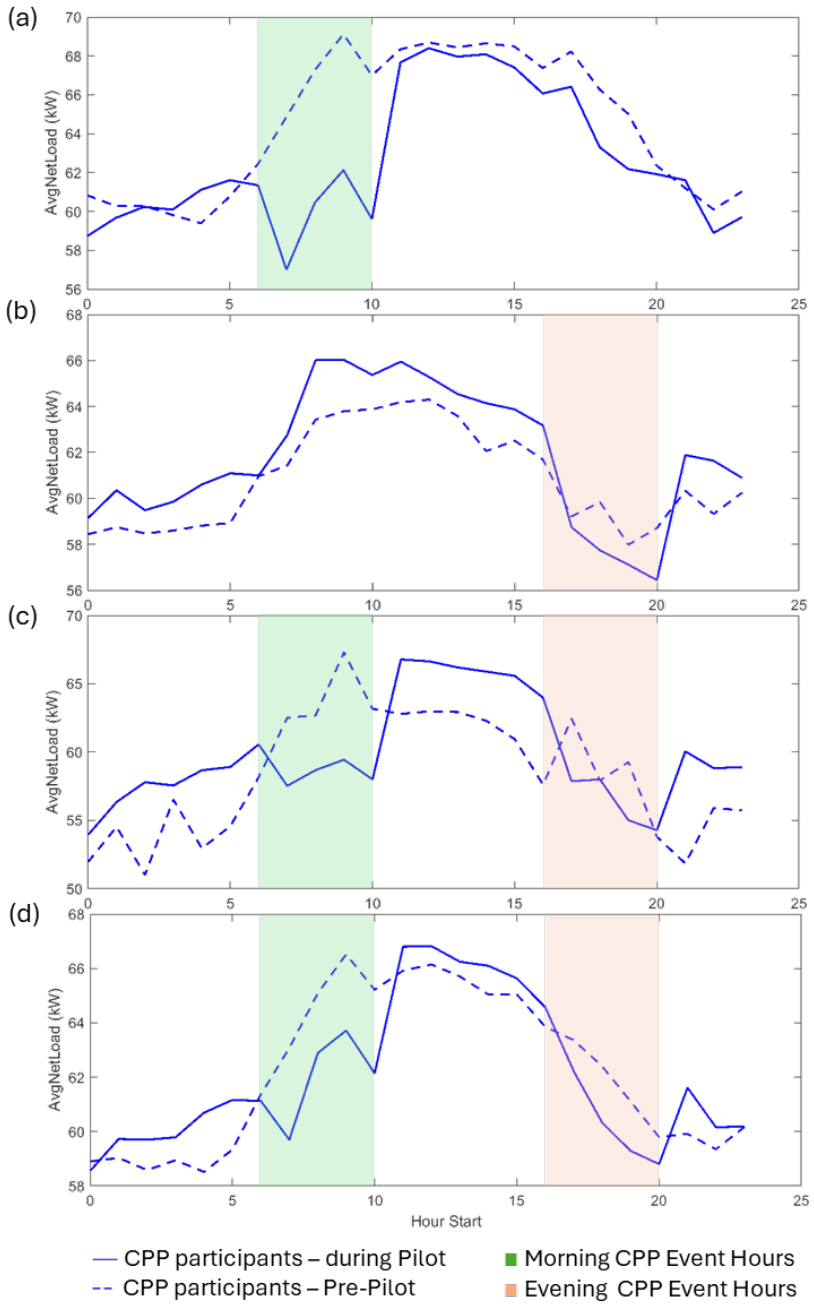
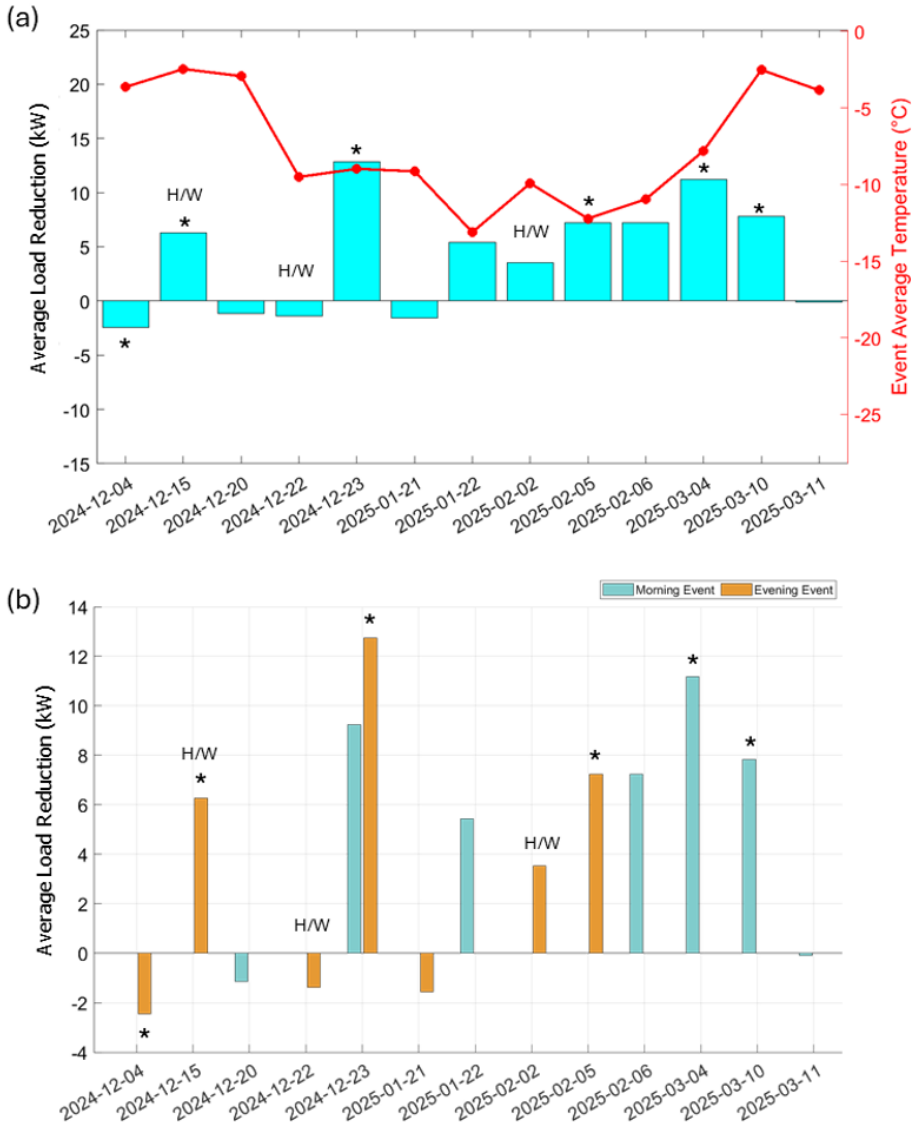


Figure 37a presents the average load reduction (kW) per CPP event date for all Phase 4 cohorts, along the corresponding event-average outdoor temperature (°C). Overall, commercial CPP participants exhibit load reductions on most event days, with a statistically significant average load reduction of 6.3 kW across all events. However, statistically significant load reductions can be observed on December 15, 2024; December 23, 2024; February 5, 2025; March 4, 2025; and March 10, 2025

(Figure 37a). Although most CPP events occurred on weekdays, three events took place on weekends. Among these, a statistically significant average load reduction of approximately 6 kW is observed on December 15, 2024 (Figure 37a).

Figure 37: (a) Average Load Reduction (kW) per CPP Event Along with Average Event Temperature (°C), and (b) Average Load Reduction per CPP Event Date by Morning, Evening, or Morning and Evening CPP Event.



* Statistically Significant (p_Value≤0.05, H/W: Holiday/Weekend)

Across all statistically significant event dates, average load reductions range from 6.3 kW to 12.9 kW, occurring on December 15, 2024, and December 23, 2024, respectively (Figure 37a). Notably, the lowest temperature at which a statistically significant load reduction is observed is −12.2 °C on February 5, 2025, corresponding to an average load reduction of 7.2 kW (Figure 37a).

Figure 37b further disaggregates results of the average load reduction by morning and/or evening events per CPP event date. Notably, commercial CPP participants exhibited an average load increase for three evening events, although the load increase (approximately 2.8 kW) was statistically significant only during the evening event on December 4, 2024. The CPP participants also showed average load increases of 1.1 kW and 0.09 kW for two morning events on December 20, 2024 and March 11, 2025, respectively, but they were not statistically significant.

There was only one instance of two consecutive CPP events in the same day, which occurred when events 5 and 6 took place on December 23, 2024. The second of these consecutive events led to the highest load reduction among CPP customers in Phase 4. This suggests that being preceded by another CPP event did not negatively affect the performance of this event. However, because Phase 4 includes only a single occurrence of consecutive events, the available data is insufficient to draw broader conclusions about the overall impact of consecutive CPP events.

Notably, performing this analysis on individual hours for each event in a similar manner to the residential rate class would further reduce the power of the regression and ultimately create statistically insignificant results.

Change in Load during Peak Events by Region

Table 44 presents the average load reduction (kW) by region (Halifax area versus the rest of Nova Scotia) for commercial CPP participants during morning, evening, and all CPP events. Commercial CPP participants located in the Halifax area exhibit statistically significant load reductions during both morning and evening events, with an average load reduction of 8.6 kW for all events, corresponding to a 10.7% relative reduction in load. In contrast, commercial CPP participants in the rest of Nova Scotia exhibit an average load increase of 0.7 kW across all events, which is not statistically significant.

Table 44: Change in Load during CPP Events by Region for Commercial CPP Participants

Parameters	Halifax Area			Rest of Nova Scotia		
	Morning Events	Evening Events	All Events	Morning Events	Evening Events	All Events
Avg. Load Reduction (kW)[a]	10.6 ± 3.8	7.0 ± 3.4	8.6 ± 3.0	-0.1 ± 0.6	-1.0 ± 1.0	-0.7 ± 0.7
Avg. Load – Commercial CPP Participants, Pre-Pilot (kW)	84.4	75.9	80	19.7	16.4	18.3
Relative Avg. Load Reduction (%)[a]	12.6%	9.2%	10.7%	-0.3%	-6.0%	-3.7%
Significance (p_Value≤0.05)	✓	✓	✓	X	X	X

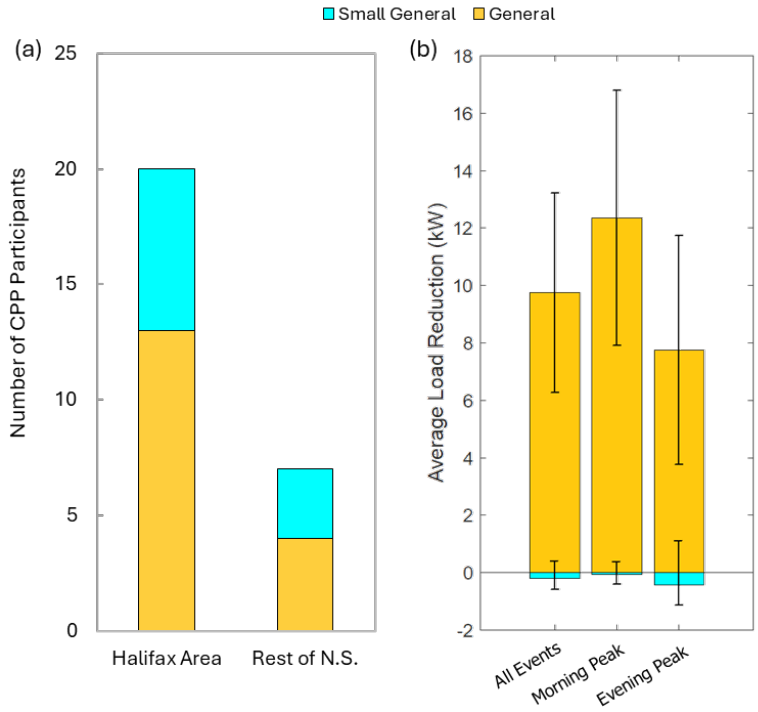
[a] Positive values represent 'Load Reduction' and Negative values represent 'Load Increase'.

The observed differences in average load reductions between the Halifax area and the rest of Nova Scotia may be partially explained by differences in the composition and sample size of business

types across regions. Figure 38a illustrates the distribution of General and Small General commercial CPP participants in the Halifax area compared to the rest of Nova Scotia. As shown, the sample size of commercial CPP participants in the rest of Nova Scotia is substantially smaller than that within the Halifax area. Specifically, the Halifax area includes 13 General commercial CPP participants, compared to only 4 General commercial CPP participants in the rest of Nova Scotia.

Given that General commercial CPP participants exhibit significantly larger average load reductions across all CPP events, compared to the statistically insignificant load reductions among Small General participants (Figure 38b), the higher number of General commercial CPP participants in the Halifax area likely contributes to the greater load reductions by the commercial CPP customers in that region, as presented in Table 44.

Figure 38: (a) Distribution of Number of General and Small General Commercial CPP Participants in Halifax Area and the Rest of Nova Scotia, and (b) the Average Load Reduction (kW) for General and Small General Business Types



6.1.2 Snapback Effect

The snapback effect refers to commercial CPP customers that use more electricity than the baseline during the hours immediately following CPP event hours, compared to the pre-pilot period. This effect was evaluated based on the same Mixed Effect approach that was applied to the load reduction calculation, but specifically for the four hours following the CPP event. As summarized in Table 45, CPP commercial participants exhibit statistically insignificant morning and evening snapback effect with an insignificant overall snapback of 0.5 kW load increase. However, the CPP participants exhibited a significant snapback of 6.9 kW of load increase during the event days with both morning and evening CPP events.

Table 45: Snapback Effect for Commercial CPP Participants

Parameters	Avg. Load Reduction [a] (kW)	Significance (p_Value≤0.05)
Morning Snapback	0.6 ± 0.9	X
Evening Snapback	-0.1 ± 1.3	X
Morning & Evening Snapback [b]	-6.9 ± 3.4	✓
Overall Snapback	-0.5 ± 1.1	X

[a] Positive values represent 'Load Reduction' and Negative values represent 'Load Increase.'

[b] Applies to the event day(s) with both morning and evening CPP peak hours.

6.1.3 Change in Load during Highest ANL Hours

Figure 39 depicts the distribution of Top 20, 50 and 88 highest ANL hours for commercial CPP participants during weekdays and weekends as well as across CPP events. As seen in Figure 39a–c, the majority of the highest ANL hours occurred on weekdays. Specifically, 55%, 36% and 27% of the top 20, 50, and 88 ANL hours, respectively, take place during peak periods. In addition, approximately 40%, 28% and 21% of all CPP events, which coincided with the highest top 20, 50 and 88 ANL hours, respectively, occurred during weekdays, while only 15%, 8% and 6% of CPP events, which coincide with top 20, 50 and 88 ANL hours, took place on Weekends.

Figure 39: Distribution of Top 20, Top 50 and Top 88 ANL Hours by Day Type (Weekday / Weekend) and Commercial CPP Events

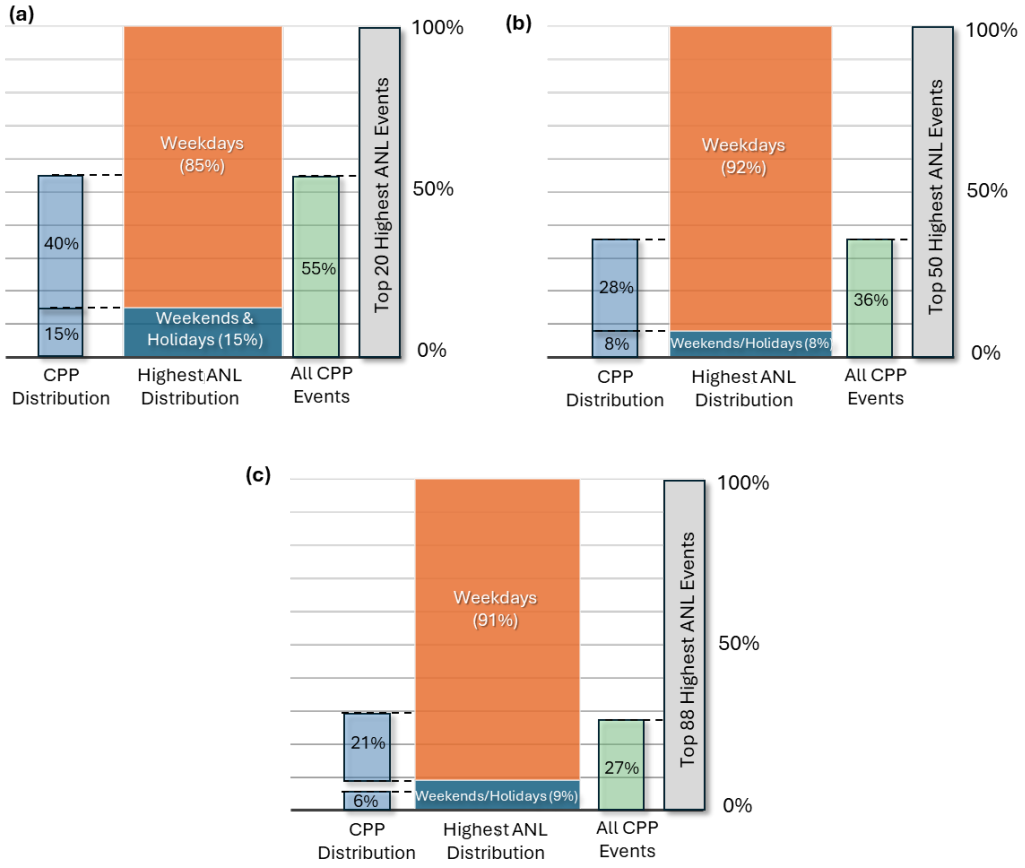


Table 46 summarizes the estimated changes in load for commercial CPP participants during the highest ANL hours overall, as well as during ANL hours that coincide with CPP peak periods. Results indicate that participants achieved statistically significant load reductions during the top 20, 50, and 88 highest ANL hours. Focusing specifically on ANL hours that coincide with CPP peak periods, the CPP participants exhibit slightly higher average load reductions during the top 20, 50 and 88 ANL hours compared to the corresponding highest ANL hours overall.

Table 46: Change in Load (kW) during Highest Winter ANL Hours for Commercial CPP Participants

Parameters	Highest ANL Hours			ANL Hours Coincide CPP Events		
	Top 20	Top 50	Top 88	Top 20	Top 50	Top 88
Avg. Load Reduction (kW)[a]	6.8 ± 3.3	6.6 ± 2.8	5.0 ± 2.1	7.4 ± 3.4	8.2 ± 3.1	7.4 ± 2.6
Avg. Load Participants, Pre-Pilot (kW)	64.4	61.4	61.6	64.1	61.3	61.2
Relative Avg. Load Reduction (%)[a]	10.6%	10.7%	8.1%	11.6%	13.3%	12.0%
Significance (p_Value≤0.05)	✓	✓	✓	✓	✓	✓

[a] Positive values represent 'Load Reduction' and Negative values represent 'Load Increase'.

6.1.4 Change in Usage

Changes in electricity usage were estimated by applying the same Mixed-Effect modeling approach that was used for estimating hourly load impact, where the change in daily usage levels was evaluated through two analyses. For the first analysis, the daily usage reduction was evaluated during event days, when at least one CPP event occurred, compared to reference days. For the second analysis, the daily electricity usage levels were evaluated for Winter and non-Winter days during the treatment period compared to the pre-pilot period.

The first analysis revealed that for all event days combined, commercial CPP participants reduced their daily electricity usage by an average of 65 kWh/day (±1.3 kWh/day) compared to reference days, which is statistically significant. The results from the second analysis are summarized in Table 47, which presents the estimated changes in daily electricity usage (kWh/day) for commercial CPP participants. As shown in Table 47, when disaggregated by day type, the CPP participants exhibit statistically significant daily usage reduction of approximately 54 kWh/day during Winter, 51 kWh/day during non-holiday weekdays in Winter, and 62 kWh/day during holiday/weekends in Winter. In contrast, the participants experienced a significant daily usage increase of 21 kWh/day during non-Winter season.

Table 47: Change in Daily Electricity Usage (kWh/day) for Commercial CPP Participants

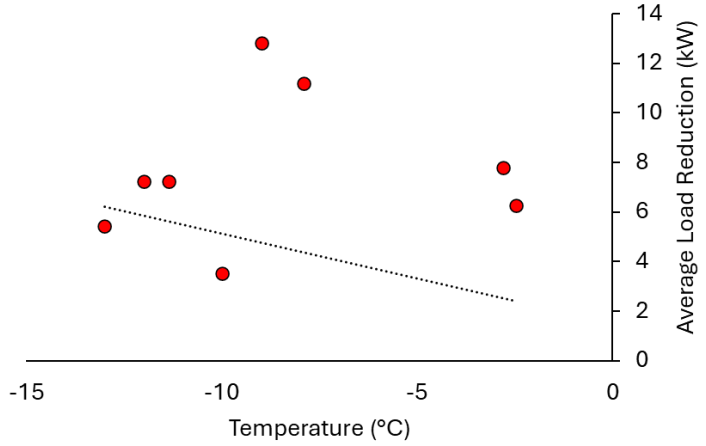
Parameters	Winter Overall	Winter – Non-Holiday Weekdays	Winter – Holiday Weekends	Non-Winter	Annual Average
Avg. Usage Reduction (kWh/day)[a]	54.0 ± 10.9	51.2 ± 11.6	62.3 ± 16.6	-21.4 ± 3.7	-12.2 ± 6.7
Avg. Usage – Commercial CPP Participants, Pre-Pilot (kWh/day)	1627	1646	1595	141	720
Relative Usage Reduction (%)[a]	3.4%	3.1%	3.9%	-15.2%	-1.7%
Significance (p_Value≤0.05)	✓	✓	✓	✓	✓

[a] Positive values represent 'Usage Reduction' and Negative values represent 'Usage Increase.'

6.1.5 Effect of Weather (Temperature) on Load Reduction

The DiD analysis reveals that the average load reduction is increased by 0.06 kW (± 0.35 kW) per 1 °C decrease in outdoor temperature, which is not statistically significant. It implies that commercial CPP customers exhibit statistically insignificant changes in their load reduction when the weather becomes colder, although the correlation between average load reduction (kW) and average outdoor temperature during CPP event days shows an upward trend with respect to colder temperature (Figure 40).

Figure 40: The Correlation of Load Reduction by Commercial CPP Participants with Outdoor Temperature



6.1.6 Effect of Consecutive CPP Events on Load Reduction

During Phase 4, like Phase 3, there was only one instance of two consecutive CPP events, which occurred when events 5 and 6 took place on December 23, 2024. The second of these consecutive events (evening event 6) led to a higher load reduction, which is statistically significant, compared to

its preceding event (morning event 5). This suggests that being preceded by another CPP event did not negatively affect the load reduction by CPP residential customers during this event. However, because Phase 4 includes only a single occurrence of consecutive events, the available data is insufficient to draw broader conclusions the overall impact of consecutive CPP events. The individual event load impacts are displayed in Figure 37.

6.2 Economic Impacts

This section presents and discusses the impact of commercial CPP tariffs on the electricity bill as well as price elasticity.

6.2.1 Change in Electricity Bills

The bill impact analysis for the commercial CPP uses the same method that was used for estimating the commercial CPP load impact analysis. In the bill impact analysis, applicable tariffs were applied in accordance with the customer type and pilot period, as summarized in Table 48. Note details on these tariffs are included in Attachment I: Riders and Tariff Structure.

Table 48: Tariffs Used for Analyzing Commercial CPP Impact on Electricity Bill

Customer Type	Period	Applicable Tariff
Treatment – General	Pre-Pilot	General Tariff – Rate Code 11
Treatment – General	Pilot	General CPP Tariff – Rate Code 73
Treatment – Small General	Pre-Pilot	Small General Tariff – Rate Code 10
Treatment – Small General	Pilot	Small General CPP Tariff – Rate Code 72

Table 49 presents the estimated average daily bill savings for all cohorts of commercial CPP participants over the Winter season in Phase 4. The commercial CPP customers experienced an average Bill increase of $11 per day, corresponding to 4.7% increase relative to their daily electricity bill in pre-pilot period, which is not statistically significant.

Table 49: Change in Daily Electricity Bill for Commercial CPP Participants

Parameters	Winter	Non-Winter	Annual Average
Avg. Bill Savings ($/day)[a]	-11.4 ± 13.1	0.1 ± 1.6	-9.8 ± 11.1
Avg. Bill, Commercial CPP Participants, Pre-Pilot ($/day)	240	25.4	178
Relative Avg. Bill Savings (%)[a]	-4.7%	0.4%	-5.5%
Significance (p_Value≤0.05)	X	X	X
[a] Positive values represent 'Bill Savings' and Negative values represent 'Bill Increase.'			

Interestingly, regardless that commercial customers demonstrated a significant increase in energy consumption during the non-Winter (Table 47), their average daily bill did not demonstrate statistically significant change as shown in Table 49. This is attributable to the decrease in CPP volumetric energy cost negating the increase in energy consumption during the non-Winter period. Furthermore, commercial CPP participants managed to reduce their annual electricity bill while increasing their overall energy consumption.

6.2.2 Price Elasticity

NS Power evaluated price elasticity to measure commercial CPP participants' responsivity to electricity prices during Phase 4 of the pilot. Specifically, NS Power evaluated Daily Price Elasticity during Winter season and annual overall, as well as the Inter-period Substitution Price Elasticity during Winter season.

Daily Price Elasticity reflects the change in overall daily electricity usage caused by changes in the average daily price ($) per kWh. It is expressed as the percent (%) change in the average electricity usage associated with a 1% increase in the daily average energy price. Inter-period Substitution Price elasticity reflects the participants' ability to substitute more expensive peak loads with less expensive off-peak loads and estimates changes in load shapes caused by a change in the peak-to-off-peak price ratio for all Winter days. It is expressed as the percent (%) change in the ratio of peak-to-off-peak average load associated with a 1% increase in the peak-to-off-peak price ratio.

The analysis reveals Daily Price Elasticity of -0.39 (± 0.07) during Winter season and -0.48 (± 0.08) annual overall. It indicates that for 1% increase in the average daily price per kWh, the average daily electricity usage decreases by 0.38% during Winter and 0.48% over the year, which are statistically significant. Furthermore, the inter-period substitution elasticity is estimated at -0.14 (± 0.15), indicating that a 1% increase in the ratio of peak-to-off-peak rates can potentially lead to a decrease of 0.14% in the peak-to-off-peak load ratio by the commercial CPP customers, which is not statistically significant.

7 MURB TOU Tariff Impacts

As this Phase represents the first year of the MURB TOU pilot program, participation was limited to 10 enrolled MURBs, with the pilot period beginning on November 1, 2024. The goal of the MURB TOU pilot is to inform if removing the demand charge for select customer segments on the General Rate will enable additional load shifting potential compared to the commercial TOU pilot. This section presents and discusses the estimated impacts of the commercial TOU pilot with respect to load and economics.

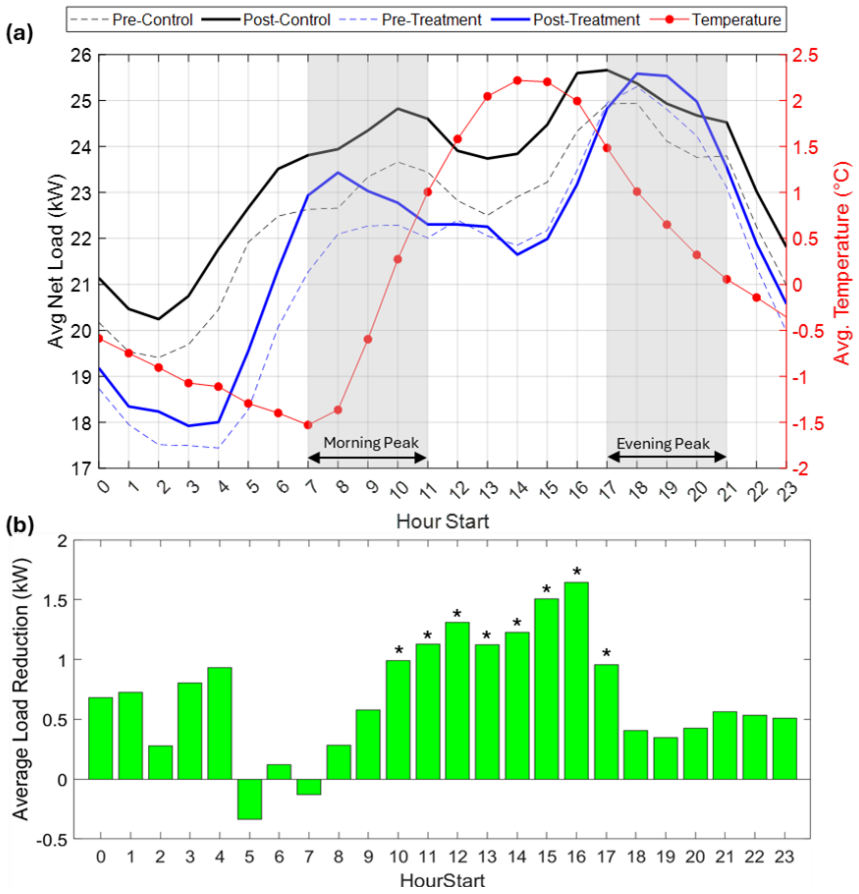
7.1 Load Impacts

This section presents and discusses the electrical load impact from the commercial MURB TOU pilot.

7.1.1 Change in Load during Peak Periods

Figure 41a illustrates the load profiles for MURB TOU participants and the control group during the pre-pilot and pilot periods with the corresponding variation in outdoor temperature. Although MURB TOU participants demonstrate reduction in load most hours except at 5 AM and 7 AM (Figure 41b), the load reduction is statistically significant from 10–11AM during morning peak period and during mid-peak hours between 11 AM – 5 PM and the first hour of the evening peak period from 5 – 6 PM (Figure 41b).

Figure 41: (a) The Hourly-Averaged Load Shapes during Winter for MURB TOU including Pre-Treatment, Post-Treatment, Pre-Control and Post-Control Groups along with the Variation of Average Outdoor Temperature during Pilot Period, and (b) the Hourly Average Load Reduction (kW)



*Represents statistically significant load reduction.

As presented in Table 50, on average, the DiD analysis reveals that MURB TOU participants exhibit a statistically significant overall load reduction of 1.9% in electrical load. Notably, average relative load reductions of 1.8% and 2.1% during the morning peak (7 – 11 AM and evening peak (5 – 9 PM) were observed respectively. Overall, during morning and evening peak periods the average reduction of approximately 480 W in load during morning and evening peak periods, which is statistically significant. Interestingly, higher relative load reductions of 5.5% and 2.2% were observed during mid-peak (11 AM – 5 PM) and off-peak hours (9 PM – 7 AM), respectively. Table 50 summarizes the results of the DiD analysis for the morning, evening, and the overall load impact. Estimated impacts are presented alongside MoE at the 90% confidence level.

Table 50: Change in Load during MURB TOU Morning and Evening Peak Hours, Mid-Peak and Overnight Peak hours, and Overall during Morning and Evening Peaks in Winter

Parameters	Morning Peak	Mid-Peak Period[b]	Evening Peak	Overnight Period[c]	Overall On-Peak
Avg. Load Reduction (kW)[a]	0.44 ± 0.49	1.34 ± 0.40	0.54 ± 0.49	0.48 ± 0.31	0.48 ± 0.35
Avg. Load – MURB TOU Participants, Pre-Pilot (kW)	24.2	24.4	25.1	22.0	24.7
Relative Avg. Load Reduction (%)[a]	1.8%	5.5%	2.1%	2.2%	1.9%
Significance (p_Value≤0.05)	X	✓	✓	✓	✓

[a] Positive values represent 'Load Reduction' and Negative values represent 'Load Increase.'

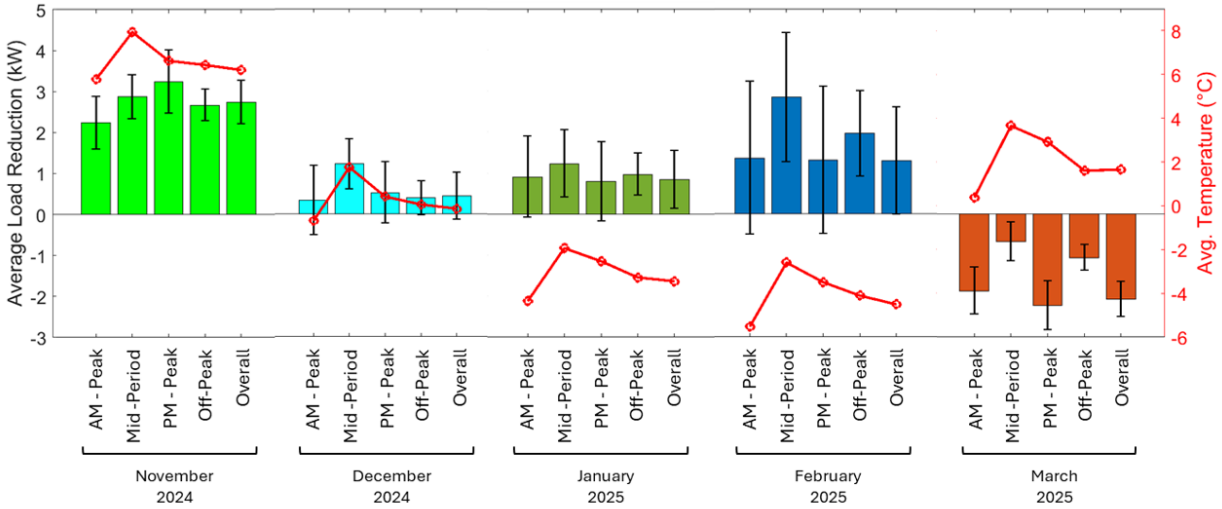
[b] Mid-peak hours are between 11 AM – 5 PM. Note: Mid-peak hours are not considered as a TOU-Peak period.

[c] Overnight period is between 9 PM – 7 AM.

Change in Load by Month during Peak Periods

Figure 42 illustrates the impact of MURB TOU on average load reduction (kW), along with corresponding average outdoor temperature (°C) during peak periods as well as mid-peak and off-peak hours by month over the Winter season (November 2024–March 2025). Overall, MURB TOU participants exhibit overall load reductions in Winter season except for March. However, the load reductions were statistically significant only in November and January. In contrast, during March, the MURB TOU customers experienced overall load increase of 9.5% during morning and evening peak hours (Figure 42). The largest load reduction of 14.5% occurred during the evening peak in November when outdoor temperatures were above 7 °C. In contrast, the MURB TOU participants experienced the highest load increase of 9.8% during the evening peak in March 2025 when average temperatures were 3 °C. Notably, during the coldest months, when average temperatures were below zero in January and February 2025, MURB TOU participants demonstrated statistically significant load reductions during mid-peak period and evening peak hours. Overall, as indicated in Table 50, MURB TOU participants showed an average load reduction of 0.48 kW during morning and evening peak hours in Winter season, which is statistically significant.

Figure 42: Average Net Load Reduction (kW) and Temperature Variation during MURB TOU Peak Period in Winter for the Months of January, February, March, November and December



7.1.2 Snapback Effect

The snapback effect refers to using more electricity during hours immediately following peak periods. This effect is evaluated based on the same DiD approach that was applied to the load reduction calculation, but specifically for the four hours following the morning and evening peak hours. As summarized in Table 51, MURB TOU participants exhibit average load reductions of 1.2 kW and 0.53 kW during the morning and evening snapback periods, respectively, although only the load reduction during morning snapback period was statistically significant.

Table 51: Snapback Effect for MURB TOU Participants in Winter

Parameters	Avg. Load Reduction (kW)[a]	Relative Avg. Load Reduction (%)[a]	Significance (p_Value≤0.05)
Morning Snapback[b]	1.20 ± 0.48	5.0%	✓
Evening Snapback[c]	0.53 ± 0.54	2.3%	X
Overall Snapback	0.92 ± 0.36	3.9%	✓

[a] Positive values represent 'Load Reduction' and Negative values represent 'Load Increase.'

[b] From 11 AM – 2 PM; [c] From 9 PM – 1 AM.

7.1.3 Change in Load during Highest ANL Hours

Figure 43 depicts the distribution of Top 20, 50 and 88 highest ANL hours for MURB TOU participants during morning peak, evening peak, mid-peak, and off-peak hours. As seen in Figure 43a-c, the majority of the highest ANL hours occurred on morning and evening peak hours.

Figure 43: Distribution of Top 20, Top 50 and Top 88 ANL Hours by MURB TOU Period

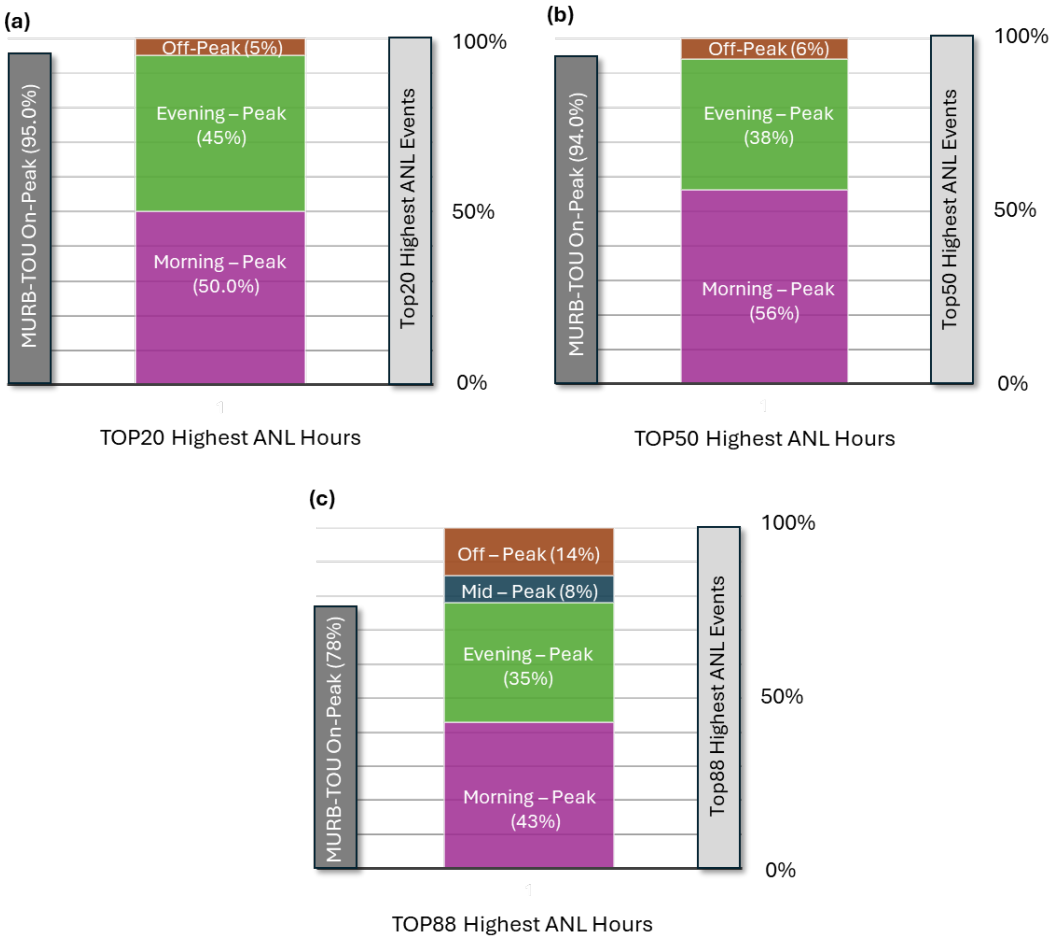


Table 52 summarizes the estimated changes in load during the highest ANL hours overall, as well as during ANL hours that coincide with TOU peak periods. Results indicate that MURB TOU participants exhibit load reduction during the top 20, 50, and 88 highest ANL hours, although only reductions during the top 50 and 88 highest ANL hours are statistically significant. When focusing specifically on ANL hours that coincide with TOU peak periods, participants exhibit load reductions of 9.6%, 12.2% and 9.1% during top 20, 50, and 88 hours, although only load reductions during top 50 and 88 are statistically significant.

Table 52: Change in Load (kW) during Highest Winter ANL Hours for MURB TOU Participants

Parameters	Highest ANL Hours			ANL Hours Coincide TOU Peak Periods		
	Top 20	Top 50	Top 88	Top 20	Top 50	Top 88
Avg. Load Reduction (kW)[a]	3.3 ± 4.0	4.2 ± 2.9	3.2 ± 2.1	2.9 ± 4.2	3.7 ± 3.0	2.8 ± 2.5
Avg. Load – MURB TOU Participants, Pre-Pilot (kW)	31.3	30.6	30.2	30.6	30.1	30.2
Relative Avg. Load Reduction (%)[a]	10.4%	13.9%	10.6%	9.6%	12.2%	9.1%
Significance (p_Value≤0.05)	X	✓	✓	X	✓	✓

[a] Positive values represent 'Load Reduction' and Negative values represent 'Load Increase.'

7.1.4 Change in Usage

Changes in daily electricity usage were estimated by applying the same DiD approach that was used for estimating hourly load impact. Table 53 presents the estimated changes in daily electricity usage (kWh/day) for MURB TOU participants.

Table 53: Change in Daily Electricity Usage (kWh/day) for MURB TOU Participants

Parameters	Winter Overall	Winter Months				
		January	February	March	November	December
Avg. Usage Reduction (kWh/day)[a]	16.5 ± 30	22 ± 45	33 ± 97	-34 ± 35	66 ± 68	11 ± 34
Avg. Usage – MURB TOU Participants, Pre-Pilot (kWh/day)	563	612	639	513	488	569
Relative Usage Reduction (%)[a]	2.9%	3.6%	5.1%	-6.6%	13%	1.9%
Significance (p_Value≤0.05)	X	X	X	X	X	X

[a] Positive and negative values represent 'Usage Reduction' and 'Usage Increase.'

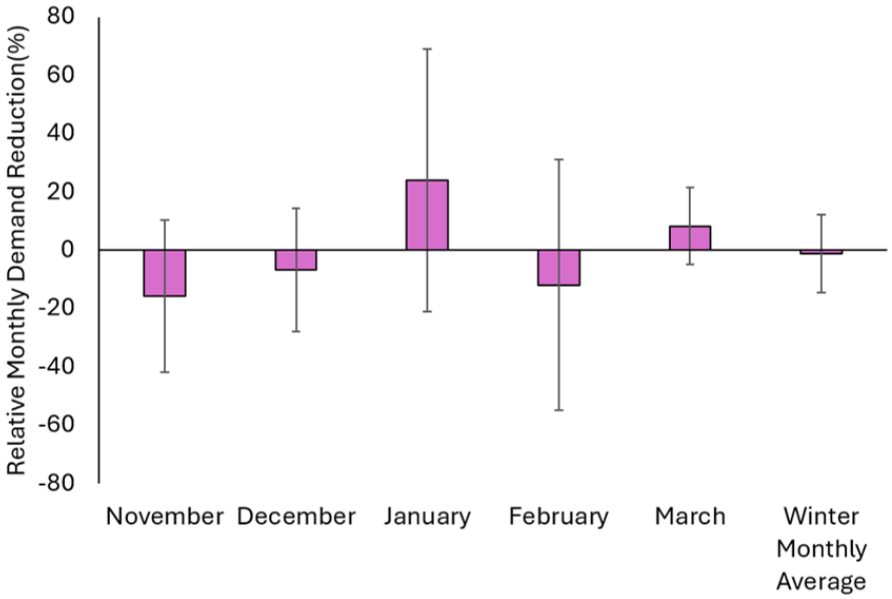
As shown in Table 53, although MURB TOU participants exhibit reductions in daily electricity usage during Winter season, the daily electricity usage reduction is not statistically significant.

7.1.5 Change in Demand

Demand for this evaluation is defined as the maximum 15-minute electricity consumption in terms of power (kW) calculated at AMI interval data frequency (i.e. every 15 minutes). Figure 44 illustrates a comparison of relative changes in monthly demand during Winter months and on average across the Winter for MURB TOU participants. Although MURB TOU participants exhibited potential indications of relative monthly demand reductions in January and March, and increases in November, December, and February, these changes were not statistically significant. Overall,

participants demonstrated statistically insignificant average changes in monthly demand during the Winter period (Figure 44).

Figure 44: Comparison of Relative Change in Monthly Demand (%) during Winter overall and among Winter Months (Jan, Feb, Mar, Nov, Dec)



Note: 'Positive' and 'Negative' relative demand reduction (%) represent 'Reduction' and 'Increase,' respectively.

Table 54 summarizes changes in monthly maximum demand among MURB TOU participants during the Winter months and for Winter 2024/25 overall. Results indicate that participants exhibited no statistically significant changes in monthly maximum demand during individual Winter months or across the Winter period.

Table 54: Change in Monthly Demand by MURB TOU Participants during Winter Months and Winter Overall

Parameters	Winter Overall	Winter Months				
		January	February	March	November	December
Avg. Monthly Demand Reduction (kW)[a]	-0.48 ± 4.45	12.9 ± 22.7	-6.60 ± 24.0	3.51 ± 5.51	-6.60 ± 11.2	-3.35 ± 10.6
Avg. Monthly Demand – MURB TOU Participants, Pre-Pilot (kW)	48.9	54.5	55.8	41.9	42.2	49.9
Relative Avg. Monthly Demand Reduction (%)[a]	-1.0%	24.0%	-11.9%	8.3%	-15.7%	-6.7%
Significance (p_Value≤0.05)	X	X	X	X	X	X

[a] Positive values represent 'Demand Reduction' and Negative values represent 'Demand Increase.'

Figure 45 illustrates the estimated relative demand reduction (%) overall and across specific TOU periods, including pre-morning peak, morning peak, morning snapback, pre-evening peak, evening peak, and evening snapback. During the Winter 2024/25 evaluation period, 5% during morning snapback hours between 11:00 AM and 3:00 PM and pre-evening peak hours between 3:00 PM – 5:00 PM. Although MURB TOU customers demonstrate increase in demand during pre-morning peak and reductions in demand during morning peak, evening peak and evening snapback hours, these changes in demand are not statistically significant (Figure 45). Notably, the effect on demand per period as visualized in Figure 45 is not a determinant for billing and should be interpreted with caution when comparing to Figure 44 which visualizes monthly demand.

Figure 45: Relative Demand Reduction (%) by MURB TOU Participants during Pre-Morning Peak (5–7 AM), Morning Peak (7–11 AM), Morning Snapback (11AM–3PM), Pre-Evening Peak (3–5 PM), Evening Peak (5–9 PM), and Evening Snapback (9PM – 1AM) during Winter

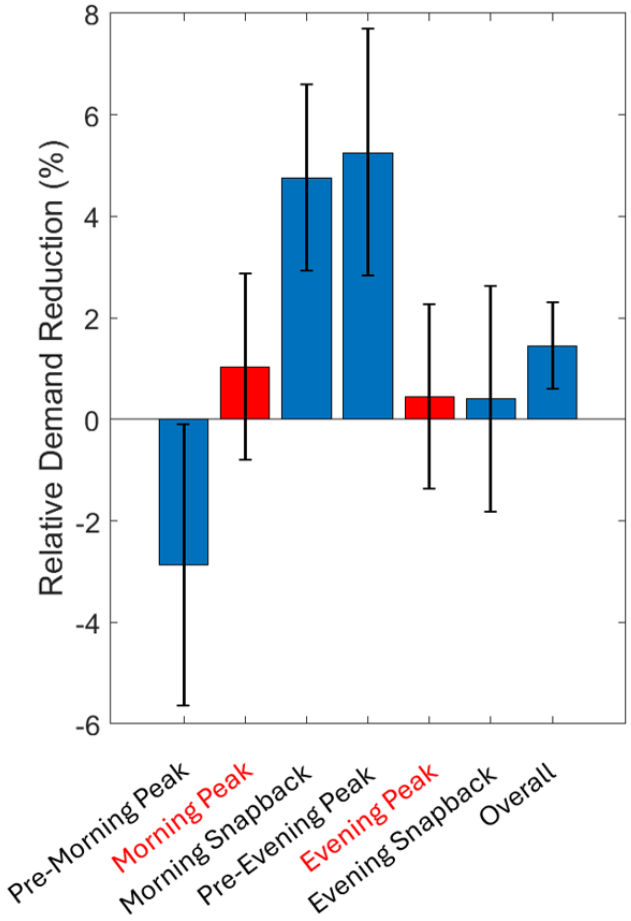


Table 55 summarizes changes in demand by MURB TOU participants during Pre-Morning Peak, Morning Peak, Morning Snapback Period, Pre-Evening Peak, Evening Peak and Evening as well as the overall and Snapback periods during Winter 2024/25. Notably, the estimated overall demand reduction of 1.4% is statistically significant, where MURB TOU participants demonstrate statistically significant demand reductions of 4.7% and 5.2% during morning snapback and pre-evening peak periods, respectively.

Table 55: Changes in Demand by MURB TOU Participants during Winter

Parameters	Pre-Morning Peak[b]	Morning Peak[c]	Morning Snapback[d]	Pre-Evening Peak[e]	Evening Peak[f]	Evening Snapback[g]	Overall Daily
Avg. Demand Reduction (kW)[a]	-0.80 ± 0.80	0.28 ± 0.56	1.32 ± 0.69	1.49 ± 0.79	0.14 ± 0.53	0.12 ± 0.59	0.36 ± 0.23
Avg. Demand – MURB TOU Participants, Pre-Pilot (kW)	27.5	28.2	27.9	29.1	34.8	29.8	25.7
Relative Avg. Demand Change (%)[a]	-2.9%	1.0%	4.7%	5.2%	0.4%	0.4%	1.4%
Significance (p_Value≤0.05)	X	X	✓	✓	X	X	✓

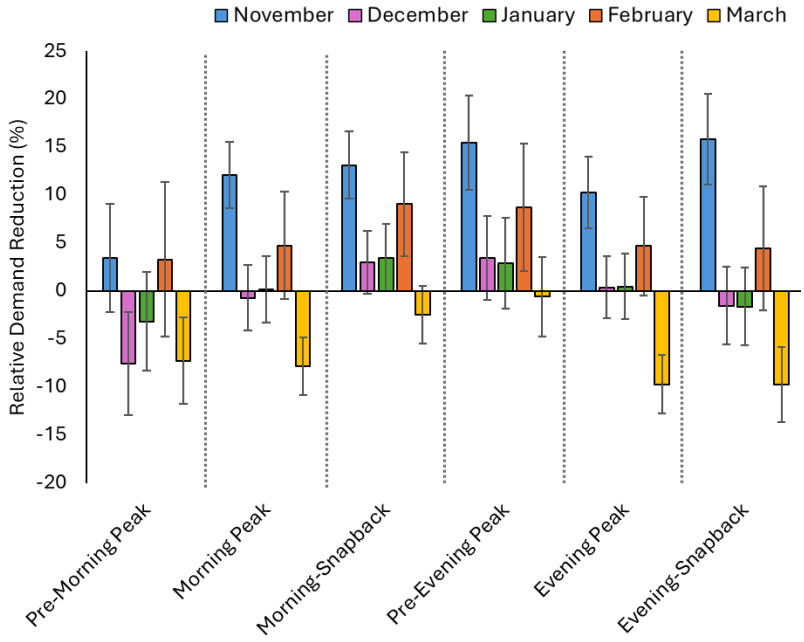
[a] Positive values represent 'Demand Reduction' and Negative values represent 'Demand Increase'.

[b] between 5 AM and 7 AM; [c] between 7 AM and 11 AM; [d] between 11 AM and 3 PM; [e] between 3 PM and 5 PM;

[f] between 5 PM and 9 PM; [g] between 9 PM and 1 AM.

Figure 46 compares the relative demand reduction (%) during TOU-related periods across Winter months. In November and February, MURB TOU participants demonstrate overall demand reductions of 5%, which is statistically significant, with consistent reductions in demand across all TOU-related periods (Figure 46). In contrast, during March, MURB TOU customers exhibit consistent increases in demand across all TOU-related periods with an overall demand increase of 7%, which is statistically significant (Figure 46). MURB TOU participants showed inconsistent changes in demand across TOU periods, which were not statistically significant overall, in December and January.

Figure 46: A Comparison of Relative Demand Reduction (%) among Winter Months (Jan, Feb, Mar, Nov, Dec) during Specific TOU Periods



Note: 'Positive' and 'Negative' relative demand reduction (%) represent 'Reduction' and 'Increase,' respectively.

Notably, customers on the MURB TOU rate do not have a demand charge (a key distinction from the SOR General Rate). As such, measuring the impact of this rate on demand is important to ensure increases in such a metric are not occurring as there is no longer a billing penalty. Interestingly, the findings from this section indicate that overall demand decreased in MURB TOU customers with March being the only month showing a statistically significant increase.

7.2 Economic Impacts

This section presents and discusses the impact of MURB TOU Tariff on the electricity bill as well as price elasticity.

7.2.1 Change in Electricity Bills

For the assessment of the economic impacts of the MURB TOU program, the same DiD approach used to estimate load and demand impacts was applied to evaluate changes in electricity bills for MURB TOU participants. In the bill impact analysis, applicable tariffs in 2025[12] were applied in accordance with the customer type and pilot period, as summarized in Table 56.

[12] Nova Scotia Power – Tariffs: January 2025

Table 56: Tariffs Used for Evaluating the Impact of MURB TOU on Electricity Bill

Customer Type	Period	Applicable Tariff
Control	Pre-Pilot	General Tariff
Control	Pilot	General Tariff
Treatment	Pre-Pilot	General Tariff
Treatment	Pilot	MURB TOU

Table 57 presents the estimated overall bill impacts and average daily bill savings by month for MURB TOU participants during the Winter 2024/25 evaluation period. MURB TOU participants experienced an average bill increase of approximately $4.5 per day although it is not statistically significant. Notably, the MURB TOU rate was designed for participants to save during the non-Winter season.

Table 57: Change in Daily Electricity Bill by Month during Winter for MURB TOU Participants

Parameters	Winter Overall	Winter Months				
		January	February	March	November	December
Avg. Bill Savings ($/day)[a]	-4.5 ± 11.4	-7.7 ± 36.7	-1.7 ± 36.5	-12.3 ± 14.9	32.4 ± 38.1	-6.3± 22.7
Avg. Bill per Day - Pre-Pilot MURBs - TOU participants ($/day)	86.0	90.0	87.9	81.4	87.3	83.8
Relative Avg. Bill Savings (%)[a]	-5.3%	-8.5%	-1.9%	-15.1%	37.1%	-7.5%
Significance (p_Value≤0.05)	X	X	X	X	X	X

[a] Positive values represent 'Bill Savings', and Negative values represent 'Bill Increase'.

Notably, the effect of changes in demand on customer savings is statistically insignificant due to the effect on monthly demand (Figure 44) used for billing also being statistically insignificant.

7.2.2 Price Elasticity

NS Power evaluated participants' responsiveness to energy price under MURB TOU pricing program, focusing on estimating daily price elasticity and inter-period Substitution Price elasticity. While Daily Price Elasticity reflects the change in overall daily electricity usage caused by changes in the average daily energy price ($) per kWh, the inter-period Substitution Price elasticity reflects the MURB participants' ability to substitute more expensive electricity usage during TOU peak hours with less expensive off-peak loads, implying shifting consumption from high-price peak periods to low-price off-peak periods. It is expressed as the percent (%) change in the ratio of peak-to-off-peak average load associated with a 1% increase in the peak-to-off-peak price ratio.

NS Power's analysis reveals a daily price elasticity of -0.17(± 0.79) during Winter, implying that for 1% increase in the average daily electricity price per kWh, the average daily electricity usage may decrease by 0.17%. The inter-period substitution elasticity is estimated at -0.032 (± 0.033), indicating that a 1% increase in the ratio of peak-to-off-peak rates might lead to a decrease of 0.032% in the peak-to-off-peak load ratio by the residential TOU customers. The daily Price Elasticity and Inter-Period Substitution Price elasticity estimated for MURBs are not statistically significant.

Findings Summary

The TVP pilot tariffs have demonstrated success in reducing load during peak periods while providing participating customers with bill savings. Both residential tariff options evaluated continue to demonstrate a strong capacity for benefiting the electrical grid and participating customers all while providing customers with choice. Positive load shift results are also emerging when evaluating the effect of the commercial rates, however, notably this appears in only the general rate participants and not in the small general rate participants. Ultimately this evaluation has provided significant evidence that the TVP Tariffs are continuing to progress towards the objective of shifting electricity usage from peak to off-peak periods/events when system utilization is lower. A summary of major findings for each tariff is presented below.

Residential TOU & CPP

- Participants continue to demonstrate statistically significant reduced load during peak periods with minimal snapback.
- For the first time, TVP combined with technology (e.g. smart thermostats) and DR (i.e. Eco Shift) was evaluated and found that significant enhancements to load reduction occurred where technology (i.e. Eco Shift + smart devices) was present.
- TOU & CPP customers who electrified their space heating reduced load during peak periods while consuming similar (TOU) and marginally more (CPP) energy throughout the year compared to those not on TVP.

Commercial TOU & CPP

- Participants for the first time have demonstrated statistically significant reduced load during peak periods. This new finding is largely attributable to improvement in methodology and increased sample sizes.
- The largest overall reductions for TOU occurred during the evening peak period in February 2025 and for CPP on the December 23 2024 evening event, when average outdoor temperatures were respectively on average −3 °C and -8 °C. These results suggest that commercial customers under the TOU & CPP tariffs can be responsive to peak periods/events during cold weather conditions. However, results for TOU peak periods differ by month, and certain CPP events did not achieve statistically significant load reductions.
- When differentiating between rate classes, Small General participants do not demonstrate responsiveness to both tariffs while the General rate class exhibits significant response to price signals.

Multi-Unit Residential Building TOU

- Despite the absence of a demand charge, MURB TOU customers did not increase their monthly demand during Winter.
- Winter energy and bill savings were negative but not statistically significant, which aligns with the rate being designed to deliver bill savings outside the Winter period.
- Overall, participants showed modest load reductions across most hours, with statistically significant reductions during evening peak periods and no evidence of snapback. Overall, these findings are directionally positive but not conclusive.

Attachment I: Riders and Tariff Structure

A summary of the TVP rate designs is included. For additional details, review the publicly available Tariff book.[13] The volumetric rates used within the billing models are summarized within this attachment in addition to visual to support understanding each TVP Tariff structure.

Riders

Although riders can change throughout a pilot Phase, to control for economic impacts associated with tariff change, a consistent tariff is used for all economic analyses. Riders are applied to all volumetric energy charges on a per kilowatt-hour basis.

Table 58: Rider Summary

TVP Group	Residential	Commercial	
Rate Class	Domestic	Small General	General
FAM ($/kWh)	0.00156	0.00156	0.00207
DSM ($/kWh)	0.00616	0.00778	0.00582
SCR ($/kWh)	0.00374	0.00355	0.00091

Tariffs

Although tariffs can change throughout a pilot Phase, to control for economic impacts associated with tariff change, a consistent tariff is used for all economic analyses.

Table 59: Tariff Summary (January 2025)

Domestic SOR	
Customer Charge	$19.17 per month
Energy Charge	$0.16931 per kWh
Domestic TOU	
Customer Charge	$19.17 per month
Energy Charge (Winter on-peak)	$0.33862 per kWh
Energy Charge (Winter off-peak)	$0.16931 per kWh
Energy Charge (Non-Winter)	$0.11426 per kWh
Domestic CPP	
Customer Charge	$19.17 per month
Energy Charge (on-peak)	$1.69310 per kWh
Energy Charge (off-peak)	$0.14222 per kWh
Small General SOR	
Customer Charge	$21.28 per month
Energy Charge (First 200 kWh)	$0.17567 per kWh
Energy Charge (All additional kWh)	$0.15841 per kWh
Small General TOU	
Customer Charge	$21.28 per month

[13] NS Power Tariff Book, effective October 2024. https://www.nspower.ca/docs/default-source/regulatory/nova-scotia-power-tariffs-2024-10.pdf

Attachment I: Riders and Tariff Structure

Energy Charge (Winter on-peak)	$0.33217 per kWh
Energy Charge (Winter off-peak)	$0.17551 per kWh
Energy Charge (Non-Winter)	$0.11731 per kWh
Small General CPP	
Customer Charge	$21.28 per month
Energy Charge (on-peak)	$1.44604 per kWh
Energy Charge (First 200 kWh off-peak)	$0.15485 per kWh
Energy Charge (All additional kWh of peak)	$0.14140 per kWh
General SOR	
Minimum Bill	$21.28 per month
Demand Charge	$10.554 per month per kW
Maximum per kWh Charge Load Factor Threshold	0.1
Energy Charge (First 200 kWh x Demand [kW])	$0.14287 per kWh
Energy Charge (All additional kWh)	$0.10990 per kWh
General TOU	
Minimum Bill	$21.28 per month
Demand Charge	$10.554 per month per kW
Maximum per kWh Charge Load Factor Threshold	0.1
Energy Charge (Winter on-peak)	$0.26243 per kWh
Energy Charge (Winter off-peak)	$0.13820 per kWh
Energy Charge (Non-Winter)	$0.09266 per kWh
General CPP	
Minimum Bill	$21.28 per month
Demand Charge	$10.554 per month per kW
Maximum per kWh Charge Load Factor Threshold	0.1
Energy Charge (on-peak)	$1.52209 per kWh
Energy Charge (first 200 kWh off-peak)	$0.11518 per kWh
Energy Charge (all additional kWh of-peak)	$0.09678 per kWh
MURB TOU	
Minimum Bill	$21.28 per month
Energy Charge (Winter on-peak)	$0.28574 per kWh
Energy Charge (Winter mid-peak)	$0.14287 per kWh
Energy Charge (Winter off-peak)	$0.12144 per kWh
Energy Charge (non-Winter on-peak)	$0.13573 per kWh
Energy Charge (non-Winter off-peak)	$0.11430 per kWh

Attachment II: ANL Hours

Table 60: Top 88 ANL Hours 2020 - 2021

Rank	Date	Start Time	Load - Wind (Adjusted Net Load) (MW)	% of Maximum Load	Halifax Temp. (°C)	TOU Period AM Peak / PM Peak / Off-Peak
1	19-Feb-21	8:00 AM	1,722.6	100.0%	-8.7	AM
2	21-Jan-21	5:00 PM	1,714.4	99.5%	-3.3	PM
3	21-Jan-21	6:00 PM	1,705.1	99.0%	-3.8	PM
4	19-Feb-21	7:00 AM	1,701.6	98.8%	-8.4	AM
5	18-Feb-21	6:00 PM	1,691.4	98.2%	-6.3	PM
6	19-Feb-21	9:00 AM	1,676.5	97.3%	-8.4	AM
7	16-Feb-21	10:00 AM	1,670.9	97.0%	-3.8	AM
8	17-Dec-20	10:00 AM	1,670.8	97.0%	-9.2	AM
9	18-Feb-21	5:00 PM	1,668.1	96.8%	-5.8	PM
10	21-Jan-21	7:00 PM	1,666.3	96.7%	-4.7	PM
11	20-Feb-21	9:00 AM	1,665.4	96.7%	-7.6	Off-Peak
12	21-Jan-21	8:00 AM	1,665.2	96.7%	-11.6	AM
13	17-Dec-20	9:00 AM	1,663.6	96.6%	-9.8	AM
14	8-Mar-21	7:00 AM	1,662.7	96.5%	-8.4	AM
15	16-Feb-21	11:00 AM	1,662.5	96.5%	-3.6	Off-Peak
16	14-Jan-21	5:00 PM	1,654.0	96.0%	1.7	PM
17	17-Dec-20	12:00 PM	1,652.8	95.9%	-6.8	Off-Peak
18	21-Jan-21	9:00 AM	1,651.4	95.9%	-11.1	AM
19	18-Feb-21	7:00 PM	1,651.2	95.9%	-6.7	PM
20	16-Feb-21	9:00 AM	1,647.4	95.6%	-4	AM
21	12-Feb-21	6:00 PM	1,646.9	95.6%	-4	PM
22	17-Dec-20	11:00 AM	1,646.9	95.6%	-8.1	Off-Peak
23	14-Feb-21	10:00 AM	1,646.5	95.6%	-7.7	Off-Peak
24	23-Jan-21	9:00 AM	1,643.8	95.4%	-8.8	Off-Peak
25	17-Dec-20	8:00 AM	1,643.5	95.4%	-10.3	AM
26	16-Feb-21	12:00 PM	1,641.7	95.3%	-2.9	Off-Peak
27	22-Jan-21	12:00 PM	1,641.0	95.3%	-3	Off-Peak
28	11-Jan-21	8:00 AM	1,640.7	95.2%	-7.6	AM
29	14-Feb-21	9:00 AM	1,640.5	95.2%	-8.3	Off-Peak
30	22-Jan-21	11:00 AM	1,639.5	95.2%	-3.2	Off-Peak
31	12-Feb-21	8:00 AM	1,636.8	95.0%	-13.1	AM
32	20-Feb-21	11:00 AM	1,636.4	95.0%	-6.6	Off-Peak
33	14-Feb-21	11:00 AM	1,635.8	95.0%	-5.2	Off-Peak
34	16-Dec-20	5:00 PM	1,634.4	94.9%	-5.9	PM
35	8-Mar-21	8:00 AM	1,631.5	94.7%	-8.6	AM
36	17-Dec-20	7:00 AM	1,630.4	94.6%	-10.6	AM
37	21-Jan-21	10:00 AM	1,629.8	94.6%	-9.6	AM
38	24-Jan-21	5:00 PM	1,629.7	94.6%	-5.1	Off-Peak
39	20-Feb-21	10:00 AM	1,629.4	94.6%	-7.3	Off-Peak
40	14-Feb-21	5:00 PM	1,628.7	94.6%	-2	Off-Peak
41	21-Jan-21	8:00 PM	1,626.6	94.4%	-5.4	PM
42	23-Jan-21	5:00 PM	1,626.3	94.4%	-2.7	Off-Peak
43	1-Feb-21	9:00 AM	1,625.7	94.4%	-4.5	AM
44	28-Jan-21	5:00 PM	1,624.2	94.3%	-1.3	PM
45	21-Jan-21	7:00 AM	1,622.9	94.2%	-11.8	AM
46	1-Feb-21	6:00 PM	1,622.5	94.2%	-2	PM
47	12-Feb-21	12:00 PM	1,622.4	94.2%	-9.2	Off-Peak
48	16-Dec-20	7:00 PM	1,621.5	94.1%	-7.7	PM
49	1-Feb-21	10:00 AM	1,621.4	94.1%	-4.1	AM
50	18-Feb-21	8:00 PM	1,620.3	94.1%	-7	PM
51	12-Feb-21	5:00 PM	1,617.5	93.9%	-4.2	PM
52	23-Jan-21	10:00 AM	1,616.9	93.9%	-7	Off-Peak
53	28-Jan-21	6:00 PM	1,616.5	93.8%	-1.8	PM

Attachment II: ANL Hours

Rank	Date	Start Time	Load - Wind (Adjusted Net Load) (MW)	% of Maximum Load	Halifax Temp. (°C)	TOU Period AM Peak / PM Peak / Off-Peak
54	20-Jan-21	5:00 PM	1,615.9	93.8%	-1.9	PM
55	11-Jan-21	7:00 AM	1,615.0	93.8%	-7.5	AM
56	12-Feb-21	7:00 PM	1,614.7	93.7%	-4.7	PM
57	21-Jan-21	4:00 PM	1,613.2	93.7%	-3	Off-Peak
58	1-Feb-21	5:00 PM	1,613.2	93.6%	-1	PM
59	12-Feb-21	9:00 AM	1,613.0	93.6%	-12.9	AM
60	22-Jan-21	10:00 AM	1,612.2	93.6%	-4.3	AM
61	19-Feb-21	6:00 AM	1,611.2	93.5%	-8.2	Off-Peak
62	19-Feb-21	6:00 PM	1,611.2	93.5%	-3.4	PM
63	14-Jan-21	6:00 PM	1,609.8	93.5%	1.3	PM
64	1-Feb-21	8:00 AM	1,609.1	93.4%	-4.5	AM
65	14-Feb-21	6:00 PM	1,608.7	93.4%	-2.2	Off-Peak
66	20-Feb-21	8:00 AM	1,608.4	93.4%	-7.8	Off-Peak
67	19-Feb-21	10:00 AM	1,608.2	93.4%	-7.6	AM
68	22-Jan-21	5:00 PM	1,607.3	93.3%	-2.6	PM
69	16-Dec-20	6:00 PM	1,606.8	93.3%	-7	PM
70	20-Feb-21	12:00 PM	1,606.3	93.3%	-5.8	Off-Peak
71	31-Jan-21	10:00 AM	1,604.9	93.2%	-7.4	Off-Peak
72	1-Feb-21	11:00 AM	1,603.5	93.1%	-3.5	Off-Peak
73	19-Dec-20	5:00 PM	1,602.6	93.0%	-0.8	Off-Peak
74	23-Jan-21	8:00 AM	1,601.5	93.0%	-9.1	Off-Peak
75	24-Jan-21	4:00 PM	1,599.6	92.9%	-5.4	Off-Peak
76	19-Feb-21	5:00 PM	1,598.7	92.8%	-3.3	PM
77	8-Mar-21	6:00 AM	1,597.1	92.7%	-7.9	Off-Peak
78	14-Feb-21	8:00 AM	1,596.9	92.7%	-9.6	Off-Peak
79	1-Feb-21	12:00 PM	1,596.2	92.7%	-3.2	Off-Peak
80	12-Feb-21	1:00 PM	1,596.1	92.7%	-7.8	Off-Peak
81	21-Jan-21	11:00 AM	1,595.3	92.6%	-8.2	Off-Peak
82	23-Jan-21	6:00 PM	1,594.0	92.5%	-2.7	Off-Peak
83	31-Jan-21	5:00 PM	1,593.7	92.5%	-2.5	Off-Peak
84	14-Feb-21	12:00 PM	1,591.2	92.4%	-3.8	Off-Peak
85	14-Jan-21	9:00 AM	1,589.3	92.3%	0	AM
86	7-Mar-21	7:00 PM	1,589.2	92.3%	-1.9	Off-Peak
87	13-Jan-21	5:00 PM	1,588.9	92.2%	0.6	PM
88	17-Dec-20	1:00 PM	1,588.3	92.2%	-5.9	Off-Peak

Table 61: Top 88 ANL Hours 2021 - 2022

Rank	Date	Start Time	Load - Wind (Adjusted Net Load) (MW)	% of Maximum Load	Halifax Temp. (°C)	TOU Periods AM Peak / PM Peak / Off-Peak	CPP Event (Yes/No)
1	6-Feb-22	7:00 PM	2,032.4	100.0%	-11.2	Off-Peak	
2	6-Feb-22	6:00 PM	2,027.3	99.8%	-10.9	Off-Peak	
3	11-Jan-22	5:00 PM	2,007.0	98.7%	-16.1	PM	
4	6-Feb-22	8:00 PM	1,993.4	98.1%	-11.3	Off-Peak	
5	27-Jan-22	8:00 AM	1,992.8	98.1%	-19.3	AM	
6	11-Jan-22	6:00 PM	1,971.9	97.0%	-16.6	PM	
7	6-Feb-22	5:00 PM	1,963.6	96.6%	-10.3	Off-Peak	
8	27-Jan-22	7:00 AM	1,957.2	96.3%	-19.5	AM	
9	27-Jan-22	9:00 AM	1,946.0	95.8%	-18.4	AM	
10	22-Jan-22	5:00 PM	1,945.6	95.7%	-8.9	Off-Peak	
11	25-Feb-22	12:00 PM	1,944.2	95.7%	-9.9	Off-Peak	
12	22-Jan-22	11:00 AM	1,938.5	95.4%	-13.5	Off-Peak	
13	22-Jan-22	12:00 PM	1,932.3	95.1%	-12.3	Off-Peak	
14	22-Jan-22	10:00 AM	1,932.0	95.1%	-15.3	Off-Peak	
15	22-Jan-22	9:00 AM	1,931.5	95.0%	-15.9	Off-Peak	

Attachment II: ANL Hours

Rank	Date	Start Time	Load - Wind (Adjusted Net Load) (MW)	% of Maximum Load	Halifax Temp. (°C)	TOU Periods AM Peak / PM Peak / Off-Peak	CPP Event (Yes/No)
16	12-Jan-22	8:00 AM	1,930.2	95.0%	-18.6	AM	Yes
17	7-Feb-22	8:00 AM	1,925.2	94.7%	-8.1	AM	
18	6-Feb-22	9:00 PM	1,925.2	94.7%	-12.7	Off-Peak	
19	1-Mar-22	8:00 AM	1,914.7	94.2%	-14.3	AM	
20	7-Feb-22	9:00 AM	1,914.1	94.2%	-8.4	AM	
21	25-Feb-22	11:00 AM	1,913.3	94.1%	-10.5	Off-Peak	
22	12-Jan-22	7:00 AM	1,912.9	94.1%	-19.4	AM	Yes
23	25-Feb-22	1:00 PM	1,910.5	94.0%	-10.5	Off-Peak	
24	12-Jan-22	6:00 AM	1,909.4	93.9%	-18.8	Off-Peak	
25	25-Feb-22	10:00 AM	1,908.9	93.9%	-10.7	AM	
26	22-Jan-22	4:00 PM	1,900.8	93.5%	-9.1	Off-Peak	
27	7-Feb-22	7:00 AM	1,900.4	93.5%	-10.2	AM	
28	25-Feb-22	9:00 AM	1,900.2	93.5%	-11.2	AM	
29	22-Jan-22	1:00 PM	1,898.9	93.4%	-11.6	Off-Peak	
30	11-Jan-22	9:00 AM	1,898.3	93.4%	-16.3	AM	
31	16-Feb-22	8:00 AM	1,897.2	93.3%	-14.6	AM	
32	22-Jan-22	8:00 AM	1,895.8	93.3%	-17.2	Off-Peak	
33	11-Jan-22	7:00 PM	1,888.8	92.9%	-16.8	PM	
34	11-Jan-22	10:00 AM	1,888.1	92.9%	-17.0	AM	
35	25-Feb-22	8:00 AM	1,886.8	92.8%	-11.7	AM	
36	1-Feb-22	6:00 PM	1,884.5	92.7%	-11.3	PM	
37	27-Jan-22	10:00 AM	1,884.2	92.7%	-16.9	AM	
38	27-Jan-22	5:00 PM	1,882.7	92.6%	-9.6	PM	
39	22-Jan-22	6:00 PM	1,881.0	92.6%	-9.0	Off-Peak	
40	1-Mar-22	7:00 AM	1,880.2	92.5%	-15.4	AM	
41	1-Feb-22	8:00 AM	1,877.3	92.4%	-15.3	AM	
42	25-Feb-22	2:00 PM	1,877.1	92.4%	-10.6	Off-Peak	
43	16-Feb-22	7:00 AM	1,876.9	92.4%	-15.9	AM	
44	22-Jan-22	2:00 PM	1,876.9	92.3%	-10.4	Off-Peak	
45	24-Jan-22	5:00 PM	1,872.3	92.1%	-5.2	PM	
46	11-Jan-22	4:00 PM	1,870.3	92.0%	-15.4	Off-Peak	
47	1-Mar-22	9:00 AM	1,869.2	92.0%	-13.1	AM	
48	7-Feb-22	10:00 AM	1,869.2	92.0%	-7.2	AM	
49	20-Dec-21	5:00 PM	1,869.1	92.0%	-5.8	PM	
50	12-Jan-22	9:00 AM	1,866.3	91.8%	-15.5	AM	Yes
51	1-Feb-22	9:00 AM	1,863.7	91.7%	-15.3	AM	
52	24-Jan-22	6:00 PM	1,861.8	91.6%	-5.2	PM	
53	22-Jan-22	3:00 PM	1,861.4	91.6%	-10.4	Off-Peak	
54	11-Jan-22	8:00 PM	1,860.4	91.5%	-16.8	PM	
55	11-Jan-22	11:00 AM	1,855.7	91.3%	-17.0	Off-Peak	
56	7-Feb-22	6:00 AM	1,855.6	91.3%	-11.0	Off-Peak	
57	16-Jan-22	5:00 PM	1,855.3	91.3%	-8.8	Off-Peak	
58	21-Jan-22	5:00 PM	1,854.9	91.3%	-12.4	PM	
59	1-Feb-22	7:00 PM	1,854.1	91.2%	-11.3	PM	
60	6-Feb-22	12:00 PM	1,853.6	91.2%	-13.3	Off-Peak	
61	20-Dec-21	6:00 PM	1,851.9	91.1%	-5.8	PM	
62	4-Jan-22	5:00 PM	1,851.6	91.1%	-8.2	PM	
63	1-Feb-22	5:00 PM	1,850.8	91.1%	-8.3	PM	
64	21-Jan-22	6:00 PM	1,850.7	91.1%	-13.3	PM	
65	27-Jan-22	6:00 PM	1,850.3	91.0%	-9.6	PM	
66	16-Feb-22	9:00 AM	1,850.3	91.0%	-14.6	AM	
67	16-Jan-22	8:00 PM	1,849.5	91.0%	-10.3	Off-Peak	
68	2-Feb-22	8:00 AM	1,849.4	91.0%	-13.6	AM	Yes
69	1-Feb-22	7:00 AM	1,848.5	91.0%	-14.4	AM	
70	6-Feb-22	10:00 AM	1,847.8	90.9%	-15.6	Off-Peak	
71	12-Jan-22	5:00 AM	1,847.2	90.9%	-19.5	Off-Peak	
72	27-Jan-22	6:00 AM	1,847.2	90.9%	-19.1	Off-Peak	

Attachment II: ANL Hours

Rank	Date	Start Time	Load - Wind (Adjusted Net Load) (MW)	% of Maximum Load	Halifax Temp. (°C)	TOU Periods AM Peak / PM Peak / Off-Peak	CPP Event (Yes/No)
73	6-Feb-22	4:00 PM	1,846.0	90.8%	-10.2	Off-Peak	
74	7-Feb-22	5:00 PM	1,845.7	90.8%	-1.0	PM	
75	6-Feb-22	9:00 AM	1,845.4	90.8%	-16.1	Off-Peak	
76	6-Feb-22	11:00 AM	1,841.3	90.6%	-14.3	Off-Peak	
77	16-Jan-22	6:00 PM	1,839.0	90.5%	-9.6	Off-Peak	
78	2-Feb-22	7:00 AM	1,838.9	90.5%	-14.8	AM	Yes
79	27-Jan-22	11:00 AM	1,835.1	90.3%	-16.9	Off-Peak	
80	16-Feb-22	6:00 AM	1,833.0	90.2%	-15.1	Off-Peak	
81	24-Jan-22	7:00 PM	1,831.0	90.1%	-6.2	PM	
82	6-Feb-22	10:00 PM	1,830.5	90.1%	-12.7	Off-Peak	
83	6-Feb-22	8:00 AM	1,829.8	90.0%	-16.2	Off-Peak	
84	16-Jan-22	7:00 PM	1,827.4	89.9%	-10.3	Off-Peak	
85	7-Feb-22	6:00 PM	1,825.0	89.8%	-1.2	PM	
86	16-Feb-22	12:00 PM	1,823.7	89.7%	-9.6	Off-Peak	
87	16-Jan22	9:00 PM	1,823.6	89.7%	-10.4	Off-Peak	
88	20-Dec-21	7:00 PM	1,823.2	89.7%	-6.4	PM	

Table 62: Top 88 ANL Hours 2022 - 2023

Rank	Date	Start Time	Load - Wind (Adjusted Net Load) (MW)	% of Maximum Load	Halifax Temp. (°C)	TOU Periods AM Peak / PM Peak / Off-Peak	CPP Event (Yes/No)
1	4-Feb-23	11:00 AM	2,163.1	100.0%	-23.8	Off-Peak	
2	4-Feb-23	10:00 AM	2,155.7	99.7%	-24.6	Off-Peak	
3	4-Feb-23	12:00 PM	2,146.9	99.2%	-22.5	Off-Peak	
4	4-Feb-23	9:00 AM	2,124.1	98.2%	-24.9	Off-Peak	
5	4-Feb-23	6:00 PM	2,110.7	97.6%	-16.5	Off-Peak	
6	4-Feb-23	5:00 PM	2,107.3	97.4%	-16.2	Off-Peak	
7	4-Feb-23	1:00 PM	2,102.8	97.2%	-20.8	Off-Peak	
8	4-Feb-23	8:00 AM	2,064.8	95.5%	-25.1	Off-Peak	
9	4-Feb-23	7:00 PM	2,062.8	95.4%	-16.1	Off-Peak	
10	4-Feb-23	4:00 PM	2,038.4	94.2%	-16.8	Off-Peak	
11	4-Feb-23	2:00 PM	2,037.5	94.2%	-19.3	Off-Peak	
12	4-Feb-23	8:00 PM	2,014.0	93.1%	-15.9	Off-Peak	
13	4-Feb-23	3:00 PM	2,012.4	93.0%	-18.1	Off-Peak	
14	4-Feb-23	7:00 AM	1,992.9	92.1%	-25.3	Off-Peak	
15	28-Feb-23	7:00 AM	1,952.9	90.3%	-14.4	AM	
16	26-Feb-23	8:00 AM	1,949.2	90.1%	-15.2	Off-Peak	
17	26-Feb-23	7:00 AM	1,947.9	90.1%	-15.6	Off-Peak	
18	5-Feb-23	9:00 AM	1,943.5	89.8%	-12	Off-Peak	
19	25-Feb-23	7:00 PM	1,941.0	89.7%	-13.9	Off-Peak	
20	4-Feb-23	9:00 PM	1,940.2	89.7%	-15.7	Off-Peak	
21	25-Feb-23	6:00 PM	1,933.2	89.4%	-13.3	Off-Peak	
22	2-Feb-23	7:00 AM	1,926.9	89.1%	-13.7	AM	
23	26-Feb-23	6:00 PM	1,926.5	89.1%	-8.9	Off-Peak	
24	26-Feb-23	7:00 PM	1,920.0	88.8%	-10.3	Off-Peak	
25	25-Feb-23	8:00 PM	1,919.9	88.8%	-14	Off-Peak	
26	4-Feb-23	6:00 AM	1,919.3	88.7%	-25.6	Off-Peak	
27	26-Feb-23	9:00 AM	1,911.7	88.4%	-14.1	Off-Peak	
28	5-Feb-23	8:00 AM	1,910.2	88.3%	-13.2	Off-Peak	
29	28-Feb-23	8:00 AM	1,907.7	88.2%	-12.6	AM	
30	28-Feb-23	6:00 AM	1,904.9	88.1%	-15	Off-Peak	
31	2-Feb-23	8:00 AM	1,897.7	87.7%	-12.9	AM	
32	27-Feb-23	7:00 AM	1,897.5	87.7%	-17.1	AM	
33	26-Feb-23	6:00 AM	1,893.7	87.5%	-15.9	Off-Peak	
34	12-Jan-23	8:00 AM	1,882.9	87.0%	-10.9	AM	

Attachment II: ANL Hours

Rank	Date	Start Time	Load - Wind (Adjusted Net Load) (MW)	% of Maximum Load	Halifax Temp. (°C)	TOU Periods AM Peak / PM Peak / Off-Peak	CPP Event (Yes/No)
35	27-Feb-23	8:00 AM	1,881.3	87.0%	-15.6	AM	
36	26-Feb-23	8:00 PM	1,875.6	86.7%	-10.9	Off-Peak	
37	26-Feb-23	5:00 PM	1,871.3	86.5%	-8.5	Off-Peak	
38	5-Feb-23	10:00 AM	1,869.3	86.4%	-9.4	Off-Peak	
39	25-Feb-23	9:00 PM	1,866.8	86.3%	-14.9	Off-Peak	
40	4-Feb-23	5:00 AM	1,866.5	86.3%	-25.9	Off-Peak	
41	12-Jan-23	7:00 AM	1,865.5	86.2%	-10.8	AM	
42	26-Feb-23	10:00 AM	1,864.9	86.2%	-12.6	Off-Peak	
43	23-Feb-23	6:00 PM	1,861.9	86.1%	-8.6	PM	
44	2-Feb-23	6:00 AM	1,858.5	85.9%	-14.8	Off-Peak	
45	5-Feb-23	7:00 AM	1,857.7	85.9%	-13.6	Off-Peak	
46	4-Feb-23	10:00 PM	1,853.9	85.7%	-15.6	Off-Peak	
47	1-Feb-23	7:00 PM	1,850.5	85.5%	-11.9	PM	Yes
48	23-Feb-23	7:00 PM	1,847.7	85.4%	-9.3	PM	
49	26-Feb-23	5:00 AM	1,844.6	85.3%	-15.5	Off-Peak	
50	1-Feb-23	6:00 PM	1,841.6	85.1%	-11.1	PM	Yes
51	1-Feb-23	8:00 PM	1,835.6	84.9%	-13	PM	Yes
52	25-Feb-23	5:00 PM	1,829.5	84.6%	-12.8	Off-Peak	
53	4-Feb-23	4:00 AM	1,827.2	84.5%	-25.9	Off-Peak	
54	2-Feb-23	9:00 AM	1,826.9	84.5%	-11.2	AM	
55	27-Feb-23	7:00 PM	1,824.7	84.4%	-10.5	PM	
56	27-Feb-23	6:00 PM	1,822.6	84.3%	-9.4	PM	
57	28-Feb-23	9:00 AM	1,821.2	84.2%	-10.1	AM	
58	26-Feb-23	11:00 AM	1,820.1	84.1%	-11.9	Off-Peak	
59	27-Feb-23	6:00 AM	1,817.9	84.0%	-17.4	Off-Peak	
60	23-Feb-23	8:00 PM	1,814.8	83.9%	-9.8	PM	
61	23-Feb-23	5:00 PM	1,814.0	83.9%	-7.8	PM	
62	24-Feb-23	8:00 AM	1,812.6	83.8%	-10.3	AM	Yes
63	4-Feb-23	3:00 AM	1,809.7	83.7%	-25.7	Off-Peak	
64	27-Feb-23	8:00 PM	1,808.7	83.6%	-12	PM	
65	12-Jan-23	9:00 AM	1,808.6	83.6%	-10.1	AM	
66	1-Feb-23	8:00 AM	1,807.6	83.6%	-14.7	AM	
67	26-Feb-23	9:00 PM	1,806.8	83.5%	-10.8	Off-Peak	
68	25-Feb-23	10:00 PM	1,804.8	83.4%	-14.7	Off-Peak	
69	4-Feb-23	2:00 AM	1,804.3	83.4%	-25.6	Off-Peak	
70	26-Feb-23	4:00 AM	1,803.6	83.4%	-15.8	Off-Peak	
71	1-Feb-23	7:00 AM	1,802.1	83.3%	-14	AM	
72	1-Feb-23	5:00 PM	1,797.4	83.1%	-9.9	PM	Yes
73	1-Feb-23	9:00 PM	1,795.8	83.0%	-13.3	Off-Peak	
74	5-Feb-23	6:00 AM	1,795.2	83.0%	-13.7	Off-Peak	
75	2-Feb-23	10:00 AM	1,794.6	83.0%	-9.2	AM	
76	27-Feb-23	9:00 AM	1,794.5	83.0%	-13.1	AM	
77	28-Feb-23	5:00 AM	1,793.7	82.9%	-14	Off-Peak	
78	11-Dec-22	5:00 PM	1,793.7	82.9%	-4.8	Off-Peak	
79	4-Feb-23	11:00 PM	1,791.1	82.8%	-15.7	Off-Peak	
80	26-Feb-23	4:00 PM	1,791.0	82.8%	-8.5	Off-Peak	
81	3-Feb-23	7:00 PM	1,790.4	82.8%	-17.2	PM	
82	4-Feb-23	1:00 AM	1,790.1	82.8%	-24.9	Off-Peak	
83	5-Feb-23	3:00 AM	1,784.6	82.5%	-15.7	Off-Peak	
84	26-Feb-23	12:00 PM	1,781.2	82.3%	-11.1	Off-Peak	
85	4-Feb-23	12:00 AM	1,778.9	82.2%	-24	Off-Peak	
86	24-Feb-23	9:00 AM	1,778.5	82.2%	-10	AM	Yes
87	12-Jan-23	5:00 PM	1,777.1	82.2%	-4.6	PM	
88	27-Feb-23	9:00 PM	1,775.1	82.1%	-12.2	Off-Peak	

Attachment II: ANL Hours

Table 63: Top 88 ANL Hours 2023 - 2024 Winter

Rank	Date	Start Time	Load - Wind (Adjusted Net Load) (MW)	% of Maximum Load	Halifax Temp. (°C)	TOU AM Peak / PM Peak / Off-Peak	CPP Event (Yes/No)
1	21-Feb-24	7:00 AM	2047.0	100.0%	-14.6	AM	Yes
2	21-Feb-24	8:00 AM	2016.7	98.5%	-14.7	AM	Yes
3	24-Jan-24	8:00 AM	1933.5	94.5%	-13.9	AM	Yes
4	31-Jan-24	8:00 AM	1930.0	94.3%	-9.7	AM	Yes
5	21-Feb-24	6:00 AM	1919.4	93.8%	-15	Off-Peak	
6	21-Feb-24	9:00 AM	1912.0	93.4%	-13.1	AM	Yes
7	31-Jan-24	9:00 AM	1911.7	93.4%	-9.4	AM	Yes
8	24-Jan-24	7:00 AM	1897.1	92.7%	-13.5	AM	Yes
9	31-Jan-24	7:00 AM	1894.7	92.6%	-9.8	AM	Yes
10	24-Jan-24	9:00 AM	1884.1	92.0%	-12.6	AM	Yes
11	31-Jan-24	10:00 AM	1879.5	91.8%	-9	AM	Yes
12	9-Feb-24	8:00 AM	1864.6	91.1%	-7.1	AM	
13	20-Jan-24	9:00 AM	1852.8	90.5%	-8.7	Off-Peak	
14	16-Feb-24	8:00 AM	1850.9	90.4%	-8.9	AM	Yes
15	6-Jan-24	5:00 PM	1850.6	90.4%	-9.7	Off-Peak	
16	24-Jan-24	10:00 AM	1850.3	90.4%	-11.4	AM	Yes
17	9-Feb-24	7:00 AM	1844.5	90.1%	-7.1	AM	
18	20-Jan-24	5:00 PM	1841.0	89.9%	-3.9	Off-Peak	Yes
19	20-Jan-24	10:00 AM	1839.9	89.9%	-7.8	Off-Peak	
20	31-Jan-24	11:00 AM	1838.1	89.8%	-8.5	Off-Peak	
21	6-Jan-24	6:00 PM	1835.5	89.7%	-10.2	Off-Peak	
22	24-Jan-24	11:00 AM	1834.7	89.6%	-9.2	Off-Peak	
23	16-Feb-24	9:00 AM	1832.1	89.5%	-8.2	AM	Yes
24	20-Jan-24	11:00 AM	1828.6	89.3%	-6.6	Off-Peak	
25	1-Jan-24	5:00 PM	1826.0	89.2%	-5.5	Off-Peak	
26	2-Jan-24	5:00 PM	1823.9	89.1%	-3.8	PM	
27	16-Feb-24	7:00 AM	1822.2	89.0%	-10	AM	Yes
28	24-Jan-24	5:00 PM	1813.5	88.6%	-5.2	PM	Yes
29	21-Feb-24	10:00 AM	1811.0	88.5%	-10.3	AM	Yes
30	24-Jan-24	12:00 PM	1810.8	88.5%	-8.6	Off-Peak	
31	9-Feb-24	9:00 AM	1808.0	88.3%	-7	AM	
32	3-Jan-24	5:00 PM	1807.4	88.3%	-3.2	PM	
33	6-Jan-24	7:00 PM	1800.4	88.0%	-10.7	Off-Peak	
34	20-Jan-24	8:00 AM	1799.5	87.9%	-9.3	Off-Peak	
35	20-Jan-24	6:00 PM	1791.1	87.5%	-4	Off-Peak	Yes
36	30-Jan-24	5:00 PM	1790.5	87.5%	-6.9	PM	
37	30-Jan-24	6:00 PM	1789.8	87.4%	-7.5	PM	
38	1-Jan-24	6:00 PM	1788.8	87.4%	-5.4	Off-Peak	
39	20-Jan-24	4:00 PM	1785.7	87.2%	-4	Off-Peak	Yes
40	22-Feb-24	8:00 PM	1784.4	87.2%	-1.9	PM	
41	9-Feb-24	6:00 AM	1783.7	87.1%	-6.9	Off-Peak	
42	1-Jan-24	4:00 PM	1783.2	87.1%	-5.2	Off-Peak	
43	3-Jan-24	6:00 PM	1782.4	87.1%	-3.7	PM	
44	31-Jan-24	12:00 PM	1781.0	87.0%	-7.7	Off-Peak	
45	2-Feb-24	5:00 PM	1780.2	87.0%	-0.2	PM	
46	31-Jan-24	6:00 AM	1779.8	86.9%	-9.6	Off-Peak	
47	16-Feb-24	10:00 AM	1779.5	86.9%	-7	AM	Yes
48	22-Feb-24	6:00 PM	1779.1	86.9%	-1.7	PM	
49	28-Jan-24	5:00 PM	1779.0	86.9%	-0.2	Off-Peak	
50	24-Jan-24	6:00 AM	1778.8	86.9%	-13	Off-Peak	
51	2-Jan-24	6:00 PM	1777.6	86.8%	-4.2	PM	
52	20-Jan-24	12:00 PM	1776.3	86.8%	-5.4	Off-Peak	
53	28-Jan-24	6:00 PM	1776.0	86.8%	-0.4	Off-Peak	
54	24-Jan-24	4:00 PM	1775.9	86.8%	-4.8	Off-Peak	
55	26-Jan-24	8:00 AM	1774.9	86.7%	-6.1	AM	

Attachment II: ANL Hours

Rank	Date	Start Time	Load - Wind (Adjusted Net Load) (MW)	% of Maximum Load	Halifax Temp. (°C)	TOU AM Peak / PM Peak / Off-Peak	CPP Event (Yes/No)
56	31-Jan-24	6:00 PM	1774.5	86.7%	-7	PM	
57	9-Jan-24	6:00 PM	1773.2	86.6%	-5.4	PM	Yes
58	31-Jan-24	5:00 PM	1772.1	86.6%	-6.5	PM	
59	26-Jan-24	12:00 PM	1772.0	86.6%	-4.4	Off-Peak	
60	26-Jan-24	10:00 AM	1770.2	86.5%	-5.3	AM	
61	3-Jan-24	8:00 PM	1769.5	86.4%	-4.5	PM	
62	30-Jan-24	7:00 PM	1768.7	86.4%	-7.9	PM	
63	22-Jan-24	8:00 AM	1768.5	86.4%	-10.7	AM	
64	26-Jan-24	5:00 PM	1767.8	86.4%	-2.4	PM	
65	22-Feb-24	7:00 PM	1766.8	86.3%	-1.8	PM	
66	6-Jan-24	8:00 PM	1766.2	86.3%	-11.1	Off-Peak	
67	9-Jan-24	5:00 PM	1765.4	86.2%	-4.7	PM	Yes
68	1-Jan-24	12:00 PM	1764.3	86.2%	-4.1	Off-Peak	
69	2-Feb-24	12:00 PM	1763.8	86.2%	-0.1	Off-Peak	
70	20-Feb-24	6:00 PM	1763.4	86.1%	-8	PM	
71	2-Jan-24	9:00 AM	1763.4	86.1%	-5.4	AM	
72	26-Jan-24	11:00 AM	1762.9	86.1%	-4.7	Off-Peak	
73	2-Feb-24	4:00 PM	1762.6	86.1%	-0.3	Off-Peak	
74	3-Jan-24	7:00 AM	1761.8	86.1%	-4.2	AM	
75	7-Jan-24	5:00 PM	1761.6	86.1%	-4.8	Off-Peak	
76	23-Dec-23	9:00 AM	1760.5	86.0%	-7.2	Off-Peak	
77	9-Jan-24	7:00 PM	1759.4	85.9%	-5.7	PM	Yes
78	1-Jan-24	7:00 PM	1759.2	85.9%	-5.5	Off-Peak	
79	24-Jan-24	1:00 PM	1759.2	85.9%	-6.9	Off-Peak	
80	2-Feb-24	1:00 PM	1759.1	85.9%	-0.1	Off-Peak	
81	3-Jan-24	7:00 PM	1758.8	85.9%	-3.4	PM	
82	1-Jan-24	1:00 PM	1758.5	85.9%	-5	Off-Peak	
83	22-Jan-24	9:00 AM	1757.7	85.9%	-9.4	AM	
84	2-Jan-24	8:00 AM	1757.5	85.9%	-6	AM	
85	16-Feb-24	6:00 AM	1757.4	85.8%	-10.7	Off-Peak	
86	26-Jan-24	9:00 AM	1756.8	85.8%	-5.6	AM	
87	23-Dec-23	8:00 AM	1755.1	85.7%	-8.3	Off-Peak	
88	28-Jan-24	7:00 PM	1754.5	85.7%	-0.4	Off-Peak	Yes

Table 64: Top 88 ANL Hours 2024 – 2025

Rank	Date	Start Time	Load - Wind (Adjusted Net Load) (MW)	% of Maximum Load	Halifax Temp. (°C)	TOU AM Peak / PM Peak / Off-Peak	CPP Event (Yes/No)
1	23-Jan-25	7	2107.9	100.00%	-13.7	AM	
2	23-Jan-25	8	2093.9	99.30%	-13.8	AM	
3	6-Feb-25	8	2053.1	97.40%	-16.7	AM	Yes
4	23-Jan-25	9	2047.2	97.10%	-12.1	AM	
5	6-Feb-25	7	2039.9	96.80%	-17.3	AM	Yes
6	23-Jan-25	6	2031.7	96.40%	-13.9	AM	
7	21-Jan-25	18	2030.6	96.30%	-10.2	PM	Yes
8	21-Jan-25	17	2030.4	96.30%	-9.3	PM	Yes
9	2-Feb-25	17	2021.5	95.90%	-11.4	Off-Peak	Yes
10	2-Feb-25	18	2017.1	95.70%	-12.3	Off-Peak	Yes
11	21-Jan-25	8	2012.5	95.50%	-15.1	AM	Yes
12	10-Feb-25	8	2011.6	95.40%	-14.7	AM	
13	5-Feb-25	18	2007.8	95.30%	-13.8	PM	Yes
14	5-Feb-25	19	1996.3	94.70%	-14.5	PM	Yes
15	13-Feb-25	7	1991.7	94.50%	-12.4	AM	
16	2-Feb-25	19	1991	94.50%	-12.3	Off-Peak	Yes
17	21-Jan-25	19	1989.9	94.40%	-11	PM	Yes

Attachment II: ANL Hours

Rank	Date	Start Time	Load - Wind (Adjusted Net Load) (MW)	% of Maximum Load	Halifax Temp. (°C)	TOU AM Peak / PM Peak / Off-Peak	CPP Event (Yes/No)
18	6-Feb-25	9	1985	94.20%	-14	AM	Yes
19	22-Jan-25	18	1984.5	94.10%	-13.2	PM	Yes
20	13-Feb-25	8	1984.5	94.10%	-12.2	AM	
21	29-Jan-25	7	1983.2	94.10%	-12.7	AM	
22	10-Feb-25	7	1982.5	94.10%	-14.7	AM	
23	29-Jan-25	8	1982	94.00%	-13.4	AM	
24	22-Jan-25	8	1980.7	94.00%	-15.7	AM	Yes
25	22-Jan-25	19	1976.5	93.80%	-13.9	PM	Yes
26	22-Jan-25	17	1975.1	93.70%	-12.2	PM	Yes
27	17-Jan-25	8	1969.4	93.40%	-9.4	AM	
28	10-Feb-25	9	1968.8	93.40%	-13.2	AM	
29	21-Jan-25	7	1967.9	93.40%	-14.9	AM	Yes
30	3-Feb-25	7	1967.8	93.40%	-9.5	AM	
31	13-Feb-25	6	1965.4	93.20%	-13	AM	
32	5-Feb-25	20	1964.6	93.20%	-14.3	PM	Yes
33	22-Jan-25	20	1962.2	93.10%	-14.4	PM	Yes
34	21-Jan-25	9	1958.1	92.90%	-14.3	AM	Yes
35	16-Jan-25	17	1957.3	92.90%	-6.7	PM	
36	3-Feb-25	8	1952.4	92.60%	-10	AM	
37	31-Jan-25	8	1951.2	92.60%	-14.9	AM	
38	21-Jan-25	20	1945.3	92.30%	-10.9	PM	Yes
39	12-Feb-25	20	1945	92.30%	-10.6	PM	
40	31-Jan-25	7	1943.7	92.20%	-15.7	AM	
41	13-Feb-25	9	1941.6	92.10%	-11.2	AM	
42	22-Jan-25	7	1938.8	92.00%	-14.6	AM	Yes
43	2-Feb-25	20	1934.5	91.80%	-12.1	Off-Peak	Yes
44	17-Jan-25	7	1933.5	91.70%	-10.7	AM	
45	12-Feb-25	19	1931.8	91.60%	-9.9	PM	
46	23-Jan-25	10	1930	91.60%	-10.3	AM	
47	5-Feb-25	17	1929.8	91.50%	-13.5	PM	Yes
48	6-Feb-25	6	1928.7	91.50%	-16	AM	Yes
49	29-Jan-25	9	1928.4	91.50%	-12.1	AM	
50	4-Mar-25	7	1925.4	91.30%	-11.9	AM	Yes
51	16-Jan-25	18	1924.6	91.30%	-6.9	PM	
52	2-Feb-25	16	1922.6	91.20%	-10.2	Off-Peak	Yes
53	11-Feb-25	8	1920.1	91.10%	-15.9	AM	
54	10-Feb-25	18	1919.1	91.00%	-6.4	PM	
55	17-Jan-25	9	1917.8	91.00%	-9.2	AM	
56	22-Jan-25	9	1916.2	90.90%	-15.4	AM	Yes
57	12-Feb-25	18	1915.6	90.90%	-9.4	PM	
58	2-Feb-25	9	1915.4	90.90%	-17.2	Off-Peak	Yes
59	10-Feb-25	17	1912.4	90.70%	-5.8	PM	
60	23-Dec-24	17	1912	90.70%	-9.2	PM	Yes
61	11-Feb-25	7	1911.7	90.70%	-16.2	AM	
62	16-Jan-25	19	1909.2	90.60%	-7	PM	
63	23-Jan-25	5	1908.5	90.50%	-13.6	AM	
64	10-Feb-25	20	1908.2	90.50%	-7.8	PM	
65	10-Feb-25	10	1907.2	90.50%	-11.9	AM	
66	29-Jan-25	10	1907	90.50%	-10.8	AM	
67	21-Jan-25	16	1906	90.40%	-9	PM	Yes
68	23-Dec-24	18	1904.8	90.40%	-10.3	PM	Yes
69	14-Jan-25	17	1902	90.20%	-2.2	PM	
70	12-Feb-25	21	1901.3	90.20%	-11.6	PM	
71	21-Jan-25	10	1900	90.10%	-13.1	AM	Yes
72	5-Feb-25	21	1899.7	90.10%	-14	PM	Yes
73	22-Dec-24	17	1899.3	90.10%	-11.7	Off-Peak	Yes
74	23-Jan-25	1	1899	90.10%	-14.9	AM	

Attachment II: ANL Hours

Rank	Date	Start Time	Load - Wind (Adjusted Net Load) (MW)	% of Maximum Load	Halifax Temp. (°C)	TOU AM Peak / PM Peak / Off-Peak	CPP Event (Yes/No)
75	23-Jan-25	0	1891.8	89.70%	-15	AM	
76	29-Jan-25	11	1891.5	89.70%	-9.7	AM	
77	1-Feb-25	9	1891.3	89.70%	-9.7	Off-Peak	
78	10-Feb-25	21	1891.3	89.70%	-10.1	PM	
79	23-Dec-24	19	1891	89.70%	-10.6	PM	Yes
80	13-Feb-25	5	1891	89.70%	-13.1	AM	
81	10-Feb-25	13	1890.7	89.70%	-7.2	PM	
82	16-Jan-25	16	1889.8	89.70%	-6.7	PM	
83	29-Jan-25	6	1889.1	89.60%	-12.9	AM	
84	10-Feb-25	12	1887.1	89.50%	-8.7	PM	
85	10-Feb-25	19	1885.6	89.50%	-6.8	PM	
86	10-Feb-25	11	1885.3	89.40%	-9.6	AM	
87	6-Feb-25	10	1885.1	89.40%	-11	AM	Yes
88	21-Jan-25	23	1884.8	89.40%	-11.2	PM	Yes

Attachment III: Methodology

The methodology for control group selection, tariff impact, and the sub-models that support these evaluations are contained within this section. To be comprehensive, all regression models are included in this section; however, when variables are consistent between regression formulas, they are not repeatedly redefined.

III.1 Datasets

The datasets used in this evaluation are summarized along with any relevant processes and cleaning steps.

Advanced Metering Infrastructure

The necessary AMI 15-minute interval data are aggregated to eight 24-hour load profiles for control group selection and hourly data for regression modelling (treatment and control). Cleaning steps specific to control group selection (Table 68) and regression modelling are defined within their respective sections.

Demographic

Environics Analytics is a Canadian data and analytics company that provides population, demographic and geographic datasets, along with analytical tools and consulting services used for market analysis and planning. For TVP, Environics Analytics provides current-year demographic data, including de-identified, aggregated and anonymized information such as income, population, household counts, diversity, etc. This represents the predominant demographic profile of households assigned to a postal code or a dissemination area. Environics Analytics is certified under the ISO's Privacy by Design standard and follows applicable Canada's privacy laws and industry best practices for protecting personal information.

Data used from Environics comes without a margin of error and is used as such despite uncertainty that arises from such aggregations. As a result, conclusions from this data should be treated as indicative, and directional in nature only, even when results are statistically significant.

Environmental

This evaluation uses Environment and Climate Change Canada temperature data[14] to control for the effect of heating degree days in the regression model and to determine CPP reference days. The temperature data is mostly without gaps, however, to eliminate gaps in weather data, three cleaning steps are performed in series for the eight weather stations.

Step 1 (Airports only): Each weather station has primary and alternative weather datasets defined by its climate ID. Airports have multiple primary weather datasets, therefore if one Climate ID has missing data the other will solely be used, if both are available the average is used.

Step 2 (All weather stations): If no primary weather data exists for a station, the nearest alternative weather station is used. The alternative weather station can be the nearest Primary weather station and/or an alternative weather station that was added to the dataset to serve only as an alternative.

[14] Environment and Climate Change Canada. (n.d.). *Historical Data – Past Weather and Climate*. Retrieved July 3, 2025, from Environment and Climate Change Canada website: https://climate.weather.gc.ca/historical_data/search_historic_data_e.html

In cases where multiple alternative data sources exist, the average is used. Table 65 provides a complete list of primary weather stations and the designated alternatives.

Table 65: Weather Station and Climate

Site	Station Name	Climate ID	Classification	Alternative Site
1	HALIFAX STANFIELD INT'L A	8,202,251	Primary	5
2	HALIFAX STANFIELD INT'L A	8,202,249	Primary	5
3	KENTVILLE CDA CS	8,202,810	Primary	1,2
4	NAPPAN AUTO	8,203,702	Primary	1,2
5	SHEARWATER RCS	8,205,092	Primary	1,2
6	SYDNEY A	8,205,703	Primary	-
7	SYDNEY A	8,205,701	Primary	-
8	TRACADIE	8,205,895	Primary	6,7,12,13
9	WESTERN HEAD	8,206,240	Primary	1,2,10,11
10	YARMOUTH A	8,206,495	Primary	11
11	YARMOUTH A	8,206,496	Primary	10
12	COLLEGEVILLE AUTO	8,201,001	Alternative	-
13	PORT HAWKESBURY	8,204,495	Alternative	-

Note: 'A' in Station Name identifies airport weather station.

Step 3: If there are still gaps in temperature data for the eight primary weather stations, a Makima cubic Hermite interpolation (i.e. a modified cubic spline interpolation) is used to fill in any remaining missing temperature data points.

Once data cleaning and interpolations step have been complete, temperature data from the nearest primary weather station to each treatment and control customer is mapped based on proximity using latitude and longitude coordinates.

Energy Savings Programs

E1 program participation[15] and evaluation reports[16] are used for control group selection balancing. Refer to Attachment III: Methodology (section III.2.4 E1 Program Balancing) for additional details.

E1's Eco Shift program identifies customers with specific devices (e.g. smart thermostats, managed electric vehicle (EV) charging, and residential batteries). In brief, the Eco Shift is an event-based DR program that controls these behind the meter technologies with the purpose of lowering load during these event periods. Notably, while the technology is only controlled by the Eco Shift program during events, these devices are permanently installed and, in some cases, can be independently controlled by the homeowner (e.g. smart thermostats). This data is used to determine if combining TVP with Eco Shift improves load impacts. Results relevant to Eco Shift are contained within the load impact in Sections 3.1 (for TOU) and 4.1 (for CPP).

[15] Provided to NS Power for the sole purpose of control group selection balancing for the TVP evaluation.

[16] EfficiencyOne, 2020-2024 DSM Evaluation Reports. NSEB Matter numbers M10056, M11071, M11630, M12186.

Property

Property Valuation Services Corporation (PVSC) is an independent, not-for-profit organization in Nova Scotia responsible for assessing all property in the province under the Nova Scotia Assessment Act. For TVP, PVSC data provides the year built, living area and housing style data. Data is mapped to individual customers using latitude and longitude data.

System & Wind Load

System load and wind load used for adjusted net load calculations are respectively sources sourced from NS Power's publicly available OASIS dataset[17] and NS Power's internal dataset.

III.2 Control Group Selection

Control group selection in Phase 4 is comprised of four modified elements that will improve the evaluation relative to previous iterations. Changes are summarized in Table 66.

Table 66: Summary of Changes to Control Group Methodology[18]

Previous Method	New Method	Projected Benefit
Neighbourhood criteria based on feeder and postal code combination	Neighbourhood criteria to be based on region (i.e. Cape Breton, Northeast, Metro, and West)	Increased pool of potential Control to Treatment matches will improve load similarity metric
Heating classification applied after initial ten control group selection candidates chosen.	Heating classification will be included in control group selection process when selecting initial ten control candidates.	Improved load similarity metric in final Control to Treatment matches by heating segment
Does not control for Eco Shift participation.	Include Eco Shift participation in control group selection process	New metric: Quantify the additional impact of combining Eco Shift with TVP.
E1 program participation balancing completed post control group selection	E1 programming will be included in control group selection process.	Improved load similarity metric in final Control to Treatment matches and streamlined control group selection process

The control group is composed of non-TVP participant customers that have the best 'Similarity Metric' relative to each individual treatment customer, as defined by equation (1), while ensuring all

[17] NS Power, OASIS, hourly total net Nova Scotia load. https://www.nspower.ca/oasis/monthly-reports/hourly-total-net-nova-scotia-load

[18] Please refer to Appendix E, Attachment 3, page 23.

evaluated sub-group combinations (Table 67) have acceptable group level load similarity and balancing for E1 programming.

Table 67: Control Group Selection TVP Sub-Groupings

Sub-Group	Possible Sub-Groupings (784 Possible Combinations)
TVP Tariff	TOU / CPP / MURB TOU
Rate Class	Domestic / Small General / General
Cohort	Cohort 1 / Cohort 2 / Cohort 3 / Cohort 4
Neighbourhood	West / Metric / Northeast / Cape Breton
Heating Classification	Steady Electric / Steady Non-Electric / Electrified / De-Electrified
Eco Shift Participation	Yes/No

This bottom-up approach of individually matching treatment and control group customers at the most granular sub-group level ensures the best possible method to quantify effects at the various subgroupings without sacrificing accuracy when sub-groups (e.g. TOU Electrified or TOU Cohort 3) are aggregated to larger groupings (e.g. TOU).

The load similarity metric calculation is determined from aggregate AMI data for each treatment customer with respect to all potential control group candidates. The AMI data will be aggregated to average hourly interval consumption and peak hourly interval consumption during Winter and non-Winter (April to October), weekdays and weekends, creating two sets of 96 data points per customer. This aggregated AMI data is then used to calculate a new two-dimensional Euclidean distance similarity metric 'SM_{AMI}' as defined by equation (1).

$$SM_{AMI} = \frac{\sum_{i=1}^{96} \frac{|Tavg_i - Cavg_i|}{Tavg_i} + \sum_{i=1}^{96} \frac{|Tpeak_i - Cpeak_i|}{Tpeak_i}}{2} \quad (1)$$

Where:

$\boldsymbol{i}$ are datapoints corresponding the 24 hours in both seasons (Winter/non-Winter) and day types (weekend/weekday) for a total of 96 different combinations.

$\boldsymbol{Tavg_i}$ is the average load of the treatment customer during datapoint i.

$\boldsymbol{Cavg_i}$ is the average load of the potential control customer during datapoint i.

$\boldsymbol{Tpeak_i}$ is the maximum load of the treatment customer occurring during datapoint i.

$\boldsymbol{Cpeak_i}$ is the maximum load of the potential control customer occurring during datapoint i.Once calculated for all potential control group customers, the top 10 per treatment customer (i.e. lowest 10 similarity metrics) for each subgroup (i.e. TVP Tariff, Rate Class, Cohort, Region, Heating Classification, and Eco Shift), are balanced for E1 program participation to control for any load altering programs administered by E1.

In addition to the processes defined within this section, cleaning steps are performed to remove customers with insufficient data from the treatment group and/or the control group; refer to Table 68.

Table 68: Treatment and Control Interval Data Cleaning Steps

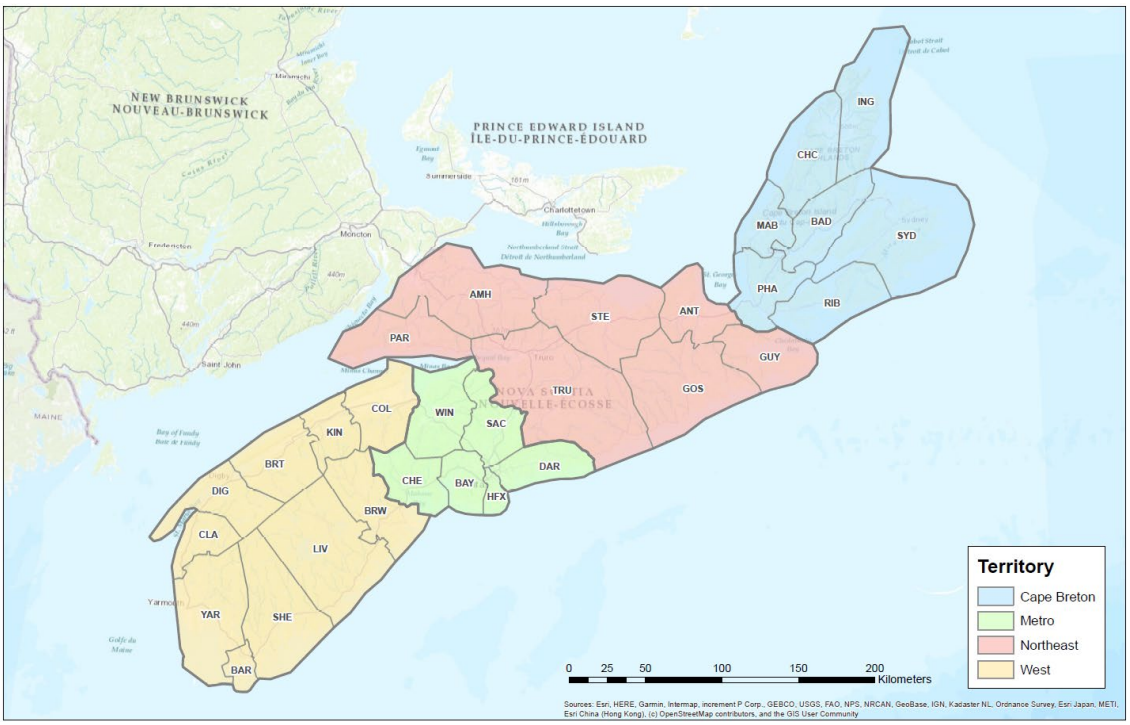
Step	AMI Data Selection – Cloud scale query to retrieve AMI data for treatment and all potential control customers
A	Limit to data to the pre-pilot period for each cohort respectively.
B	Limit to only data which is stamped as "actual"[19]
C	Only customers with over the air (OTA) billing enabled are considered.
D	Remove all seasonal and net metering customers (control only).
E	Limit to Domestic, Small General and General rate class customers.
Step	**Control Group Selection**
A	Limit list to customers with ≥ 50% of necessary data.
B	Limit list of treatment customers to those in the pilot for a minimum of 60 days.

III.2.1 Neighbourhood Criteria

The intent of using neighbourhood criteria is primarily to choose control customers who have similar housing types and environmental weather patterns relative to treatment customers. In previous evaluations, the volume of AMI data that could be processed was limited by local machine computations, as such, the previous methodology sacrificed a larger control group selection pool for the distinct advantage in minimizing the volume of AMI data. However, given the requirement to analyze distinct heating classifications, a broader control selection pool is required. To meet this requirement, the new method which analyzes all AMI data with a territory for each control group selection cohort is enabled by cloud scale analytics, which became part of NS Power's analytical toolbelt in 2024. The neighbourhood criteria territories are shown in Figure 47.

[19] AMI interval reads can either be classified as "actual" or "estimated". Actual reads are measured consumption were estimated reads are based on historical usage. Estimate reads are rectified for billing purposes however these datapoints are not overwritten in the cloud scale analytics platform where the data is retrieved.

Figure 47: Map of Nova Scotia by Control Group Selection Neighbourhood Criteria Territories

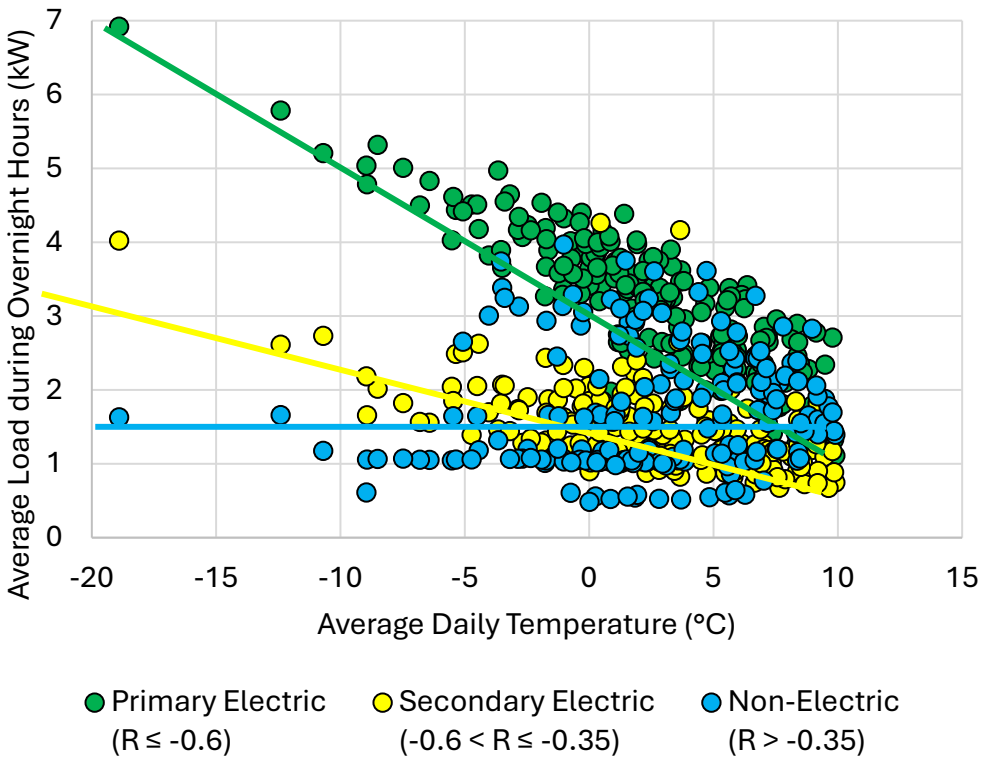


Note that depot names are included in Figure 47, although for control group selection only the four territories are used. For example, a treatment customer from Metro, must be matched to a control customer also from Metro. The benefit of this proposed change includes simplification of control group selection process by removing the need for billing data by directly accessing AMI data for large (100k+ population groups).Using this method, the potential control group population of AMI data is increased significantly, which will improve the match precision and enable the addition of heating classification & Eco Shift to control group selection.

III.2.2 Heating Classification

Customers are first classified into three categories (Primary, Secondary, Non-Electric) based on their electricity consumption as visualized in Figure 48.

Figure 48: Example of Heating Correlation Model Classifications



The heating classification method uses AMI and nearby weather station temperature data for individual premises to classify space heating types. AMI data was restricted to overnight hours (i.e. 10 PM – 5 AM) where the average daily temperature is below 10 °C. The model operates on the principle that the more negatively correlated a customer's consumption is to temperature (i.e. consumption increases while temperature decreases) the likelier they are to be heated with electricity. Using the correlation coefficient, 'R', a customer would be classified as secondary electric (-0.6<R≤-0.35) or primary electric (-0.6≤R).[20]

The model's output is simplified for the purposes of this evaluation to consider all customers as primary or secondary electric to 'electric' (i.e. R≤-0.35). Additionally, a mean consumption threshold during the top 20 consumption days of 0.5 kW or greater was required. This threshold is applied to avoid classifying customers with significantly low consumption during cold days regardless of correlation coefficient. Both metrics must be satisfied to be classified as electric, refer to Table 69.

Table 69: Electric Space Heating Classification Requirements

Mean load during top 20 consumption days	R≤-0.35	R>-0.35
< 0.5 kW	Non-Electric	Non-Electric
≥ 0.5 kW	Electric	Non-Electric

[20] The correlation coefficient, R, was calculated between Average Daily Temperature (°C) and Average Power Consumption during Overnight Hours (kW) to quantify the strength and direction of the linear relationship between the two variables.

The classification was completed in the pre-pilot and pilot period for each participant and potential control customer to create four heating classifications; refer to Table 70.

Table 70: Heating Classification Definition

Heating Classification	Pre-Pilot	Pilot Period
Steady Electric	Electric	Electric
Steady Non-Electric	Non-Electric	Non-Electric
Electrified	Non-Electric	Electric
De-electrified	Electric	Non-Electric

The heating classification is used to ensure treatment and control customers are from the same classification during control group selection.

Notably, the heating classification methodology and its application to the TVP evaluation has been modified in each Phase of the evaluation, this progression is documented in Attachment IV: Historical Methodological Changes.

III.2.3 Eco Shift

A new addition to the TVP evaluation included the effect of combining the Eco Shift administered by E1 with TVP. Control group selection for these customers was incorporated into this evaluations methodology to ensure that Treatment to Control pairings for Eco Shift sub-groups had satisfactory similarity metrics. To facilitate control group selection, a list of known Eco Shift participants was provided to NS Power by E1. Customers in both TVP + Eco Shift and TVP by itself were limited to a control group selection pool of non-Eco Shift participants while adhering to all other control group selection criteria.

To ensure the effect of Eco Shift and TVP are understood properly, NS Power requested a list of Eco Shift events from E1, provided in Table 71. Notably nearly all Eco Shift events are CPP events as the programs were aligned through collaborative efforts between E1 and NS Power.

Table 71: List of Eco Shift Events and Their Corresponding Starting/Ending Times, with Event Participant Distinction (All Eco Shift vs. CPP Only)

Participants [a]	Eco Shift Event Date	Event Hour Window	Is CPP Event?	Is Weekend?
All	04-Dec-2024	5 PM – 9 PM	✓	x
CPP	15-Dec-2024	5 PM – 9 PM	✓	✓
All	20-Dec-2024	7 AM – 11 AM	✓	x
CPP	22-Dec-2024	5 PM – 9 PM	✓	✓
All	23-Dec-2024	5 PM – 9 PM	✓	x
CPP	23-Dec-2024	7 AM – 11 AM	✓	x
All	21-Jan-2025	5 PM – 9 PM	✓	x
All	22-Jan-2025	7 AM – 11 AM	✓	x
CPP	02-Feb-2025	5 PM – 9 PM	✓	✓
All	05-Feb-2025	5 PM – 9 PM	✓	x
All	06-Feb-2025	7 AM – 11 AM	✓	x
All	12-Feb-2025	5 PM – 9 PM	x	x

[a] Where "All" designates the event applies to all Eco Shift participants regardless of whether they are on a standard offer rate (SOR), TOU, CPP or any other tariff. "CPP" defines events that are specific to those in CPP and Eco Shift to maximize Eco Shift efficacy during CPP event periods.

III.2.4 E1 Program Balancing

Treatment and control customer participation in E1 programs (Home Energy Assessment, Green Heat, Appliance Retirement, Efficient Product Installation, Small Business Energy Solutions, Business Energy Rebates, and Custom) are balanced using this process to mitigate confounding effects of EOne programs on TVP results. It should be noted Eco Shift is balanced separately with its own control sub-group as indicated in Table 67.

i. The lowest similarity metric (equation (1)) is prioritized with alternates continuously chosen until the associated E1 energy savings in both the potential control and treatment are equal for each subgroup. To complete this balancing, E1 has provided NS Power with customer participation in each of these programs from 2021 through 2024. Using the list, the effect for E1 programming on energy consumption is controlled for using the following steps (i. through v.). Customers in the treatment and potential control group selection pool are mapped to their corresponding E1 programs (if any).

The energy savings filed for each of the program in the year it was administered[21] is average per participant and adjusted for line loss factors. These program savings are allocated to each customer in treatment and potential control based on program year and TVP cohort using equation (2) and Table 72.

$$E1\ Energy\ Savings = ProgramSavings_y * Factor_{y,c} \quad (2)$$

[21] EfficiencyOne, 2020-2024 DSM Evaluation Reports. NSEB Matter numbers M10056, M11071, M11630, M12186.

Table 72: Phase 4 E1 Program Year and TVP Cohort Savings Correction Factor

E1 Program Year (y) / TVP Cohort (c)	2021	2022	2023	2024
Cohort 1	0.67	1	1	0.75
Cohort 2	0	0.67	1	0.75
Cohort 3	0	0	0.67	0.75
Cohort 4	0	0	0	0.42

For example, if a Cohort 2 TVP customer or the potential control customer for this TVP participant had a home energy assessment completed in 2022, a factor of 0.67 would be multiplied by the program savings for that program in that year (4344 kWh annually) to yield a E1 energy savings of 2,910 kWh annually in Phase 4.

The savings correction factor logic is to account for customers participating in an E1 program part way through either the pre-pilot or pilot period. For instance, continuing with the example above, a Cohort 2 TVP participant's pre-pilot period was from November 1, 2021 to October 31, 2022, thus 10 months of the pre-pilot was in 2022. If they participated in an E1 program in 2022, some of the pre-pilot data would be affected by the E1 program. Since NS Power does not know during which month the customer participated in the Home Energy Assessment, it is assumed in this method that participation occurred in the middle of the year (i.e. July 1, 2022). Using this assumption, eight of the twelve months (November 2021 to June 2022 / 67% of control year) were unaffected by the E1 program, and as such will not be fully included in pre-pilot AMI data and should be accounted for in control group balancing to not bias the pilot period results.

ii. The total E1 programming energy savings for the treatment group and the corresponding group of top control candidates, determined by similarity metric are evaluated and compared.

iii. If the treatment group displays higher or lower E1 annual energy savings relative to the initial control group (first pick), alternative control group customers are selected from the "top ten control" match with higher or lower E1 energy savings until the balance is zero or near zero for the control group.

iv. Once a balance of zero, or near zero energy savings between treatment and control is achieved, this process is repeated for all control sub-group combination (i.e. TVP Tariff, Rate Class, Region, Heating Classification, Eco Shift Participation).

The equation used to define where a control and treatment group have balanced the expected energy savings due to EOne is defined by equation (3).

$$E1\ Balance\ Acccuracy = \left(1 - \frac{\left|T_{savings} - C_{savings}\right|}{T_{savings}}\right) x100\% \quad (3)$$

Where:

$\boldsymbol{T_{savings}}$ is the sum of annual treatment group E1 program savings

$\boldsymbol{C_{savings}}$ is the sum of annual control group E1 program savings

III.2.5 Match Accuracy

Once a final control group has been established, the quality of the control group selection match is defined by the 'Match Accuracy', refer to equation (4).

$$Match\ Accuracy = \left(1 - \frac{\overline{|T_t - C_t|}}{\overline{T}}\right) x100\% \quad (4)$$

Where:

$\boldsymbol{T_t}$ is the treatment power at time 't' where t ranges from 1 to 96

$\boldsymbol{C_t}$ is the control power at time 't' where t ranges from 1 to 96

$\boldsymbol{\overline{T}}$ is the average of all 96 power datapoints for the treatment group

III.2.6 CPP Reference Days

Although the regression model controls for time synchronous (i.e. zero hour lag-lead) temperature effects in the form of heating degree days (HDD), it is critical to find reference days with similar temperature profiles to the event day to minimize the variable bias in the results that would be caused by lagging temperature effect on customer consumption. Notably, the methodology for reference day selection has remained consistent for TVP throughout all evaluations.

Reference days are used as control period days for both treatment and control TVP customers (i.e. Pilot Period = 0) in the regression. Reference days cannot be other completed or cancelled CPP event days or holidays[22]. Additionally, reference days must be within +/- 20 days of the event day (Criteria A) and be of the same weekday type (Criteria B).

There are three weekday types:

Type 1: Monday or Friday (MF)

Type 2: Tuesday, Wednesday, Thursday (TWT)

Type 3: Saturday or Sunday (SS)

The three weekday types are used to find days where customers have similar consumption patterns. Grouping residential electricity consumption days into categories like MF, TWT, and weekends (SS) reflects common behavioral patterns that influence energy use. These groupings help control for behavioural patterns that effect energy consumption.

While Criteria A and B define which days can be potential CPP reference days, they do not quantify which of these days are the best for TVP regression. To determine the best CPP reference day for each event by weather station, temperature for the 24 hours pre-event (Criteria C) and the temperature at the beginning of the peak event (Criteria D) are compared with potential reference days and ranked according to similarity using the Euclidean distance method. The 24-hour Euclidean distance measurement (Criteria C) is defined by equation (5).

[22] Critical Peak Pricing Tariff, "Critical Peak Event Procedure," Condition (1) definition of 'holiday,' page 2.

$$Criteria_C = \sqrt{\sum_{i=0}^{i=23}(E_i - R_i)^2} \quad (5)$$

Where:

$\boldsymbol{i}$ defines the hours before the start of the CPP event. For example, if the event starts at 7 AM, $i = 0$ at 7 AM for both the event and reference data.

$\boldsymbol{E_i}$ is the event day temperature at hour i

$\boldsymbol{R_i}$ is the reference day temperature at hour i

Using the $\mathrm{Criteria_C}$ metric, each candidate reference day is assigned a rank in ascending order, denoted as $\mathrm{Rank_C}$. Specifically, the reference day with the minimum value of $\mathrm{Criteria_C}$ is assigned $\mathrm{Rank_C} = 1$, the day with the second-lowest value is assigned $\mathrm{Rank_C} = 2$, and so forth, such that lower values of $\mathrm{Criteria_C}$ correspond to higher (i.e., better) rankings.

$\mathrm{Criteria_D}$ is calculated by taking the absolute difference between the temperature at the starting time of the event on the event day (E_0) and all potential Reference days (R_0). $\mathrm{Criteria_D}$ is then ranked in the same manner to $\mathrm{Criteria_C}$ to form $\mathrm{Rank_D}$. The rankings from both $\mathrm{Criteria_C}$ & $\mathrm{Criteria_D}$ are combined using equation (6) to form $\mathrm{Rank_{CD}}$.

$$Rank_{CD} = \sqrt{Rank_C^2 + Rank_D^2} \quad (6)$$

This method weighs the ranking of a 24-lagging temperature and the concurrent temperature at the start of the event to determine the most suitable reference day for each CPP event for each weather station. In many cases, the best reference day for each event is the same for all weather stations; however, occasionally, the reference day for a given event day varies between weather stations, especially for weather stations on opposite sides of the province where temperatures can differ more significantly. For additional clarity, refer to the results of this year's CPP reference day model in Table 8 (section 2.4 CPP Reference Days).

III.3 Regression Models

The regression models are divided into three sections, Residential TOU & CPP, Commercial TOU & CPP and MURB TOU.

Notably, these regression models utilize hourly AMI data on a per-customer basis. This shift from previous evaluation reports, combined with increased sample sizes in Phase 4, has resulted in smaller margins of error (MoE) relative to earlier TVP evaluation reports.

III.3.1 Residential TOU & CPP

This section presents the methodology used to determine the load, usage, and economic impact of the residential TOU and CPP tariffs. The estimates for load and economic impacts are rounded and reported according to the number of significant figures supported by the margin of error at the 90% confidence level to avoid implying false precision. Although some values are reported with three significant figures, most are presented with two significant figures.

III.3.1.1 Load & Usage Impact Regression Model

The regression model used for load and usage impacts is presented in equation (7).

$$Load_{it} = \beta_0 + \beta_1.Treatment_i + \beta_2.PilotPeriod_t + \beta_3.(Pilot \times Treatment)_{it} + \beta_4.HDD_{it} + \beta_5.(Pilot \times Treatment)_{it}.HDD_{it} + \varepsilon_{it} \quad (7)$$

Where:

***Load**$_{it}$* is the average load in 'kW' by customer '*i*' for the time period of '*t*' (e.g. each TOU peak period of 4 hours or CPP event period of 4 hours). For usage impact, ***Load**$_{it}$* is replaced by ***Energy**$_{it}$* which is the energy consumption in 'kWh/day' by customer '*i*' for the time period of '*t*'.

β_0 is the intercept (the average load that is independent of any of the independent variables).

***Treatment**$_i$* is a binary variable (dummy variable) that equals 0 for control group customers and 1 for treatment group customers under TOU or CPP tariffs.

PilotPeriod**$_t$* is a binary variable (dummy variable) that equals 0 for the period before TOU Tariff is in effect, and equals 1 during the pilot period when the TOU tariffs are in effect. For CPP Tariff, PilotPeriod is replaced by ***DayType where it equals 1 for CPP events and equals 0 for Reference days.

***(Pilot×Treatment)**$_{it}$* is a binary variable that equals 1 only for the treatment customers during pilot period; otherwise, it equal 0.

***HDD**$_{it}$* is a variable linked to the heating degree-day (with a balance temperature of 12 °C) value at time *t* and the weather station associated with weather station of premise *i*. This variable is generally the average HDD minus a fixed value determined by mean of the average HDD values.

β_1 is the coefficient describing the correlation between being a treatment customer and the average load.

β_2 is the coefficient describing the correlation between being during the pilot period and the average load.

β_3 is the coefficient describing the correlation between being a treatment customer during pilot period and the average load.

β_4 is the coefficient describing the correlation between HDD and the average load.

β_5 is the coefficient describing the correlation between *Pilot*×*Treatment*, *HDD* and the average load.

$\beta_4+\beta_5\times$***HDD*** represents the effect of TVP on average Load.

ε_{it} is the regression error.

For daily electricity usage impact analysis, ***Load**$_{it}$* in equation (7) is replaced by ***Energy**$_{it}$* which is the energy consumption in **kWh/day** by customer '*i*' at time '*t*'.

TVP customers in Eco Shift will be evaluated from December 1, 2024 – February 28, 2025. For comparison, TOU and CPP customers that are not in Eco Shift will be evaluated within the same time-period. Relative to the TVP regression model without Eco Shift, two additions have been made. The first, a binary variable that represents TVP and Eco Shift enrolment during the pilot period. The

second, the addition of a random intercept, changing the model from a fixed effects to mixed-effects model. Given the relatively small participant count of Eco Shift with TVP (TOU = 115 , CPP = 94) and heterogeneity of baseload and device type (e.g. smart thermostats, managed EV charging), a careful selection process between Fixed Effect and Mixed Effect modeling was considered, where the choice of the analysis approach can affect the precision and reliability of the estimated TVP program impacts. A similar comparison for Commercial customers is accounted for in Attachment V: Validation of Mixed Effects Regression, although this is a different TVP group, the principles discussed for commercial participants relate to the residential TVP x Eco Shift participants, as such a mixed effect model was deemed to be more accurate. Refer to equation (8) for the complete TVP x Eco Shift regression model.

$$\begin{aligned} Load_{it} = {} & (\beta_0 + u_i) + \beta_1.Treatment_i + \beta_2.PilotPeriod_t \\ & + \beta_3.(Pilot \times Treatment)_{it} + \beta_4.HDD_{it} \\ & + \beta_5.(Pilot \times Treatment)_{it}.HDD_{it} \\ & + \beta_6.(Pilot \times Treatment)_{it}.EcoShift_i + \varepsilon_{it} \end{aligned} \quad (8)$$

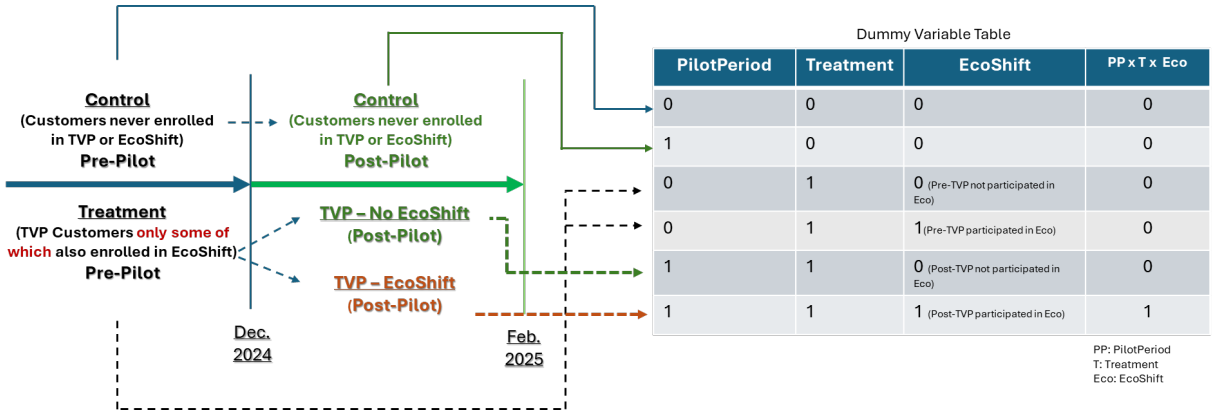
Where:

β_6 is the additional impact due to Eco Shift for TVP customers enrolled in Eco Shift program

u_i is the random intercept.

Figure 49 illustrates the diagram for binary variable matrix corresponding to the pilot groups for the Eco Shift TVP analysis. It should be noted that Eco Shift is focused on residential customers for this Phase of the TVP evaluation.

Figure 49: Eco Shift Visualization of Binary Variables



Dummy Variable Table

PilotPeriod	Treatment	EcoShift	PP x T x Eco
0	0	0	0
1	0	0	0
0	1	0 (Pre-TVP not participated in Eco)	0
0	1	1 (Pre-TVP participated in Eco)	0
1	1	0 (Post-TVP not participated in Eco)	0
1	1	1 (Post-TVP participated in Eco)	1

PP: PilotPeriod
T: Treatment
Eco: EcoShift

III.3.1.2 Economic Impact Regression Model

The regression model used for billing impact is as follows in equation (9).

$$DailyBill_{it} = \beta_0 + \beta_1.Treatment_i + \beta_2.PilotPeriod_t + \beta_3.(Pilot \times Treatment)_{it} + \beta_4.HDD_{it} + \beta_5.(Pilot \times Treatment)_{it}.HDD_{it} + \varepsilon_{it} \quad (9)$$

Where:

DailyBill$_{it}$ is the average Daily Bill in $ per day by customer '*i*' for the time period of '*t*'.

β_0 is the intercept reflecting the average Daily Bill which is independent of any independent variables).

β_1 is the coefficient describing the correlation between being a treatment customer and the average daily bill.

β_2 is the coefficient describing the correlation between being during the pilot period and the average daily bill.

β_3 is the coefficient describing the correlation between being a treatment customer during pilot period and the daily bill.

β_4 is the coefficient describing the correlation between *HDD* and the average daily bill.

β_5 is the coefficient describing the correlation between *Pilot*×*Treatment*, *HDD* and the daily bill.

β_4+β_5×HDD represents the effect of TVP on the average daily bill.

The regression models for daily price elasticity and inter-period substitution price elasticity are presented in equations (10) and (11), respectively.

$$\begin{aligned} ln(Daily\ Avg\ Usage\ kWh)_{it} = \\ = \beta_0 + \beta_1.Treatment_i + \beta_2.PilotPeriod_t \\ + \beta_3.(Pilot \times Treatment)_{it} + \beta_4.ln(Temp_K)_{it} \\ + \beta_5.(Pilot \times Treatment)_{it}.ln(Temp_K)_{it} \\ + \beta_6.\ln\left(Avg\ Energy\ Price \frac{\$}{kWh}\right) \\ + \beta_7.\left(Avg\ Energy\ Price \frac{\$}{kWh}\right).ln(Temp_K)_{it} + \varepsilon_{it} \end{aligned} \quad (10)$$

Where:

ln(Daily Avg Usage kWh) is the natural logarithm of daily average electricity usage in kWh.

β_0 is the intercept.

ln(Temp_K) is the natural logarithm of Temperature in Kelvin.

β_4 is the coefficient reflecting the effect of natural logarithm of temperature on daily average usage.

β_5 reflects the effect of natural logarithm of temperature on TVP impact on daily average usage.

β_6 is the coefficient describing the correlation between natural logarithm of daily usage and the natural logarithm of average energy price, reflecting the customers' price responsivity.

β_7 reflects the effect of natural logarithm of temperature on customers' price responsivity.

$\beta_6+\beta_7\times ln(Temp_K)$ represents the daily price elasticity.

$$\begin{aligned} ln\left(\frac{AvgPeak\ Load\ kW}{Avg\ OffPeak\ Load\ kW}\right)_{it} = \\ = \beta_0 + \beta_1.Treatment_i + \beta_2.PilotPeriod_t \\ + \beta_3.(Pilot \times Treatment)_{it} + \beta_4.\Delta Temp_{it} \\ + \beta_5.(Pilot \times Treatment)_{it}.\Delta Temp_{it} \\ + \beta_6.\ln\left(\frac{Peak\ Energy\ Price}{OffPeak\ Energy\ Price}\right) \\ + \beta_7.\ln\left(\frac{Peak\ Energy\ Price}{OffPeak\ Energy\ Price}\right).\Delta Temp_{it} + \varepsilon_{it} \end{aligned} \quad (9)$$

Where:

ln(Avg Peak Load kW/Avg OffPeak Load kW) is the natural logarithm of Peak to Off-Peak load ratio.

Δ(Temp) is the difference between average peak temperature and average off-peak temperature.

β_5 reflects the effect of temperature difference between peak and off-peak on TVP impact.

β_6 is the coefficient describing the correlation between logarithm of Peak to Off-Peak load ratio and the logarithm of Peak to Off-Peak Energy Price ratio.

β_7 reflects the effect of temperature difference between peak and off-peak on customers' ability to substitute less expensive with expensive electricity usage.

$\beta_6+\beta_7\times$ ***Δ (Temp)*** results in the inter-period substitution price elasticity.

III.3.2 Commercial TOU & CPP

This section presents the methodology used to determine the load, usage, and economic impact of the commercial TOU and CPP tariffs. The estimates for load and economic impacts are rounded and reported according to the number of significant figures supported by the margin of error at the 90% confidence level to avoid implying false precision. Although some values are reported with three significant figures, most are presented with two significant figures.

Linear Mixed effect model – The evaluation of Commercial CPP and TOU impacts is based on panel data estimation approach with pre-pilot and pilot treatment data in the absence of control group using a Mixed-Effects regression analysis. Given the relatively small sample sizes for commercial TOU (n = 50) (Table 33) and commercial CPP (n = 28) (Table 42), and heterogeneity of commercial TVP participants including General and Small General businesses, a careful selection process between Fixed Effect and Mixed Effect modeling for Commercial-TVP impact evaluation was considered, where the choice of the analysis approach can affect the precision and reliability of the estimated TVP program impacts. This comparison is accounted for in Attachment V: Validation of Mixed Effects Regression where the mixed effects model is determined to be a solution to heterogeneity.

Within subject design – Due to the absence of control group, NS Power used semi-difference-in-difference (semi-DiD) method, where NS Power estimate load and economic impacts using a within-customer modeling framework that compares event days to matched reference days (CPP) and pilot to pre-pilot (TOU).

Analysis by Cohort – Opposite to the residential load impact evaluation, an analysis by cohort is not feasible for commercial due to low sample sizes introducing statistical insignificance.

Weather Adjusted – To ensure that premise-specific load patterns are not primarily driven by HDD, NS Power applied a weather-adjustment refinement to hourly load data for each premise based on the marginal effect of HDD on electricity load using the regression model in equation (11).

$$L_{i,t} = \alpha + \beta_i . HDD_t + \varepsilon_{i,t} \quad (11)$$

Where:

$\boldsymbol{L_{i,t}}$ is the hourly consumption (kW) for premise 'i' at time 't'.

$\boldsymbol{\alpha}$ is the regression intercept.

$\boldsymbol{\beta_i}$ is the unique premise identifier.

$\boldsymbol{HDD_t}$ are the heating degree days (°C) at time 't'

$\boldsymbol{\varepsilon_{i,t}}$ is the Regression error

The adjusted load ($L_{i,t}^{adj.}$) was obtained by subtracting the estimated HDD-driven component ($\beta_i . HDD_t$) from the hourly electricity consumption ($L_{i,t}$) for each premise as shown in equation (12).

$$L_{i,t}^{adj.} = L_{i,t} - \beta_i . HDD_t \quad (12)$$

Seasonality – In addition to baseload and business type heterogeneity, seasonality of the business is a factor that affects the load shape among Commercial CPP and TOU participants, making the average consumption pattern not necessarily representative of the consumption pattern of any one of the premises. Customers on a seasonal service under Regulation 3.3 are not eligible for TOU or CPP rates and are therefore excluded. However, customers not on seasonal service may still have seasonal load profiles.

Identification of businesses with seasonal load profiles and removing them from the load data can make the data more representative, especially for analyzing the Commercial CPP and TOU load impact during Winter. NS Power conducted a premise-level seasonal analysis to identify and exclude non-Winter-oriented (seasonal) businesses from the evaluation.

A weather-adjusted hourly load (kW) was used for each premise for the seasonal analysis, where the monthly average load values were calculated for each Winter month (November–March) and each non-Winter month (April–October). Then, the Seasonal Load Ratio (SLR) was evaluated for each premise by calculating the ratio of mean Winter to non-Winter hourly consumption for each premise,

Attachment III: Methodology

following common segmentation practice in demand research (e.g., Borenstein, 2005[23]; Hledik et al., 2010[24]); refer to equation (13).

$$SLR_i = \frac{\overline{\left(L_{i,W}^{adj.}\right)}}{\overline{L_{i,S}^{adj.}}} \quad (13)$$

Where:

$\overline{L_{i,W}^{adj.}}$ is the Winter average adjusted-load for each premise.

$\overline{L_{i,S}^{adj.}}$ is the non-Winter averaged adjusted-load for each premise.

A seasonal load ratio (SLR) threshold of 0.7 was used to indicate substantially lower electricity usage (>30% drop in electricity usage) during the Winter period. A premise was classified as seasonal if at least two Winter months exhibited SLR smaller than the SLR threshold of 0.7, indicating an average electricity usage reduction of >30% during the Winter period compared to the mean load during the non-Winter period.

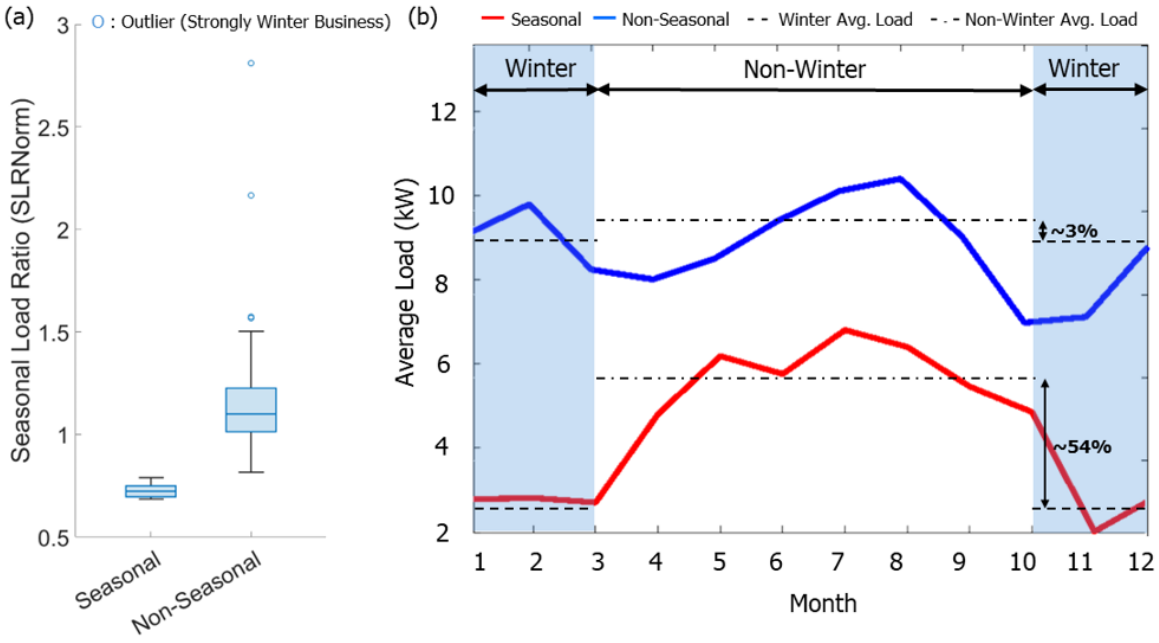
Figure 50a presents the results of the seasonality segmentation for all cohorts of TVP commercial participants based on the SLR. As shown in Figure 50a, most businesses are classified as non-seasonal, with a median SLR value greater than 1.1, while five businesses are identified as seasonal, exhibiting a median SLR value below 0.6. The outliers with relatively large SLR values within the non-seasonal segment correspond to strongly Winter-oriented businesses; these premises were included in the non-seasonal category and included in the evaluation of commercial TVP impacts.

Figure 50b presents monthly load patterns of seasonal and non-seasonal commercial participants during Winter and non-Winter seasons. Seasonal businesses show an approximately 54% increase in average load (kW) during non-Winter relative to Winter. In contrast, non-seasonal businesses exhibit approximately 3% change in average load across seasons.

[23] Borenstein S., The Long-Run Efficiency of Real-Time Retail Electricity Pricing, 2005.

[24] Hledik, R., Faruqui, A., & Sergici, S., Assessing the Impact of Dynamic Pricing in Northern California, Electricity Journal, 2010.

Figure 50: (a) Seasonality Segmentation of All Cohorts of TVP Commercial Participants Based on the Seasonal Load Ratio (SLR), Distinguishing Seasonal and Non-Seasonal Businesses; and (b) Monthly Load Patterns of Seasonal and Non-Seasonal Commercial Participants during Winter and Non-Winter Seasons



III.3.2.1 Load and Usage Impact Regression Model

Considering the methodological choices discussed above, the commercial TOU and CPP load/usage, billing as well as daily and substitution price elasticity are described by the equations (14), (15), (16), and (17) respectively.

$$Load_{it} = (\beta_0 + u_i) + \beta_1.Treatment_i + \beta_2.PilotPeriod_t + \beta_3.(Pilot \times Treatment)_{it} + \beta_4.HDD_{it} + \beta_5.(Pilot \times Treatment)_{it}.HDD_{it} + \varepsilon_{it} \quad (14)$$

Where:

- β_0 *is the baseline,* u_i is the random intercept reflecting the deviation from the baseload for premise *i*.

For the description of the other variables, refer to the descriptions for equation (7). For daily electricity usage impact analysis, $Load_{it}$ in equation (14) is replaced by $Energy_{it}$ which is the energy consumption in **kWh/day** by customer '*i*' at time '*t*'.

III.3.2.2 Economic Impact Regression Model

$$DailyBill_{it} = (\beta_0 + u_i) + \beta_1.Treatment_i + \beta_2.PilotPeriod_t + \beta_3.(Pilot \times Treatment)_{it} + \beta_4.HDD_{it} + \beta_5.(Pilot \times Treatment)_{it}.HDD_{it} + \varepsilon_{it} \quad (15)$$

$$
\begin{aligned}
ln(Daily\ Avg\ Usage\ kWh)_{it} = \\
&= (\beta_0 + u_i) + \beta_1.Treatment_i + \beta_2.PilotPeriod_t \\
&+ \beta_3.(Pilot \times Treatment)_{it} + \beta_4.ln(Temp_K)_{it} \\
&+ \beta_5.(Pilot \times Treatment)_{it}.ln(Temp_K)_{it} \\
&+ \beta_6.\ln\left(Avg\ Energy\ Price\frac{\$}{kWh}\right) \\
&+ \beta_7.\left(Avg\ Energy\ Price\frac{\$}{kWh}\right).ln(Temp_K)_{it} + \varepsilon_{it}
\end{aligned}
\tag{16}
$$

$$
\begin{aligned}
ln\left(\frac{AvgPeak\ Load\ kW}{Avg\ OffPeak\ Load\ kW}\right)_{it} = \\
&= (\beta_0 + u_i) + \beta_1.Treatment_i + \beta_2.PilotPeriod_t \\
&+ \beta_3.(Pilot \times Treatment)_{it} + \beta_4.\Delta Temp_{it} \\
&+ \beta_5.(Pilot \times Treatment)_{it}.\Delta Temp_{it} \\
&+ \beta_6.\ln\left(\frac{Peak\ Energy\ Price}{OffPeak\ Energy\ Price}\right) \\
&+ \beta_7.\ln\left(\frac{Peak\ Energy\ Price}{OffPeak\ Energy\ Price}\right).\Delta Temp_{it} + \varepsilon_{it}
\end{aligned}
\tag{17}
$$

Where: the coefficients and variables are as described earlier in equations.

Due to the absence of control groups for commercial TVP, the variable '*Treatment*' is excluded from equations (14), (15), (16) and (17) for load and economic impact analysis of commercial TOU and CPP, however, it is included in the MURB TOU regression.

III.3.3 MURB TOU

The evaluation of MURB TOU is based on panel data estimation approach with matched control groups and pre-pilot data using the difference-in-difference (DiD) approach similar to the residential tariffs. Given the relatively small sample size (n = 10) for MURBs, the choice of the modeling approach can affect the precision and reliability of the estimated program impacts, as such a review of the effect of choosing Fixed or Mixed effects was conducted (Attachment V: Validation of Mixed Effects Regression). Upon analysis, the MURB TOU load and billing impact regression will use a mixed-effects approach.

III.3.3.1 Load and Usage Impact Regression Model

The same regression as equation (14) was used for load impact and usage impact analyses for MURB TOU.

III.3.3.2 Economic Impact Regression Model

The same regression as equations (15), (16) and (17) was used for bill saving and price elasticity analysis for MURB TOU.

Attachment III: Methodology

In addition to the metrics calculated for commercial TOU and CPP, the effect on demand was evaluated. This analysis estimates demand using 15-minute average calculated every 15 minutes (i.e. AMI interval data), whereas actual billing demand is the 15-minute average calculated every 5 minutes. As such demand used in the evaluation is an estimate of billed demand, however, does serve as reasonable proxy for determining demand effect for the purposes of TVP EM&V.

Attachment IV: Historical Methodological Changes

All methodological modifications were made through collaboration with stakeholders and/or consultants. These changes and their progression have been summarized with two purposes.

1. Informing readers of the caveats with comparing results between different evaluation reports (i.e. Phases) can be subject to bias due to changes in methodology.
2. These methodological changes represent, in part, the progress in rate innovation and evaluation methodology developed throughout the TVP pilot program. This progress should be documented to capture the value this program has provided to itself and so that future pilot programs can benefit from this as a guide.

IV.1 Control Group Selection

Control group selection methodology is documented by the Phase, for example (Phases 1,2,3) indicates a methodology that was used in Phases 1, 2 and 3 that is no longer applicable to Phase 4 onwards unless otherwise noted.

IV.1.1 CPP (Phase 1)

Consistent with the approved evaluation plan, the CPP evaluations used a within-subject control group methodology. In practice this meant that there was no control group for CPP customers, rather the only control was treatment customers during the respective CPP reference day. After the first year of the evaluation, it was recommended by Econoler to modify the approach and create a control group for CPP customers; thus, creating consistency between CPP and TOU evaluations.

IV.1.2 E1 Program Balancing (Phase 1)

No balancing for E1 program effects was completed. As a result, the effects associated with E1 programs were not controlled for and could influence TVP EM&V results. Subsequent evaluations (i.e. Phase 2 onwards) have all balanced control group selection for E1 participation.

IV.1.3 Neighbourhood Criteria & Load Similarity Metric Data (Phase 1, 2, 3)

In the previous TVP evaluations (i.e. Phases 1-3) control selection included 2 stages.

Stage 1

The first stage determined the potential control candidate group using three increasing sizes of selection pools with pre-pilot billing data. The primary neighbourhood criteria, street name (i.e. the smallest pool) was used first. Treatment and control candidate customer billing data is linearized into monthly consumption and compared using similarity metric ‘SM’, a two-dimensional Euclidean distance calculation as defined by equation (18).

$$SM_{Monthly} = \frac{\sum_{i=1}^{12} \frac{|TM_i - CM_i|}{TM_i}}{n} \quad (18)$$

Where:

$\boldsymbol{TM_i}$ is the linearized monthly consumption for the treatment customer for month 'i'

$\boldsymbol{CM_i}$ is the linearized monthly consumption for the control customer for month 'i'

$\boldsymbol{n}$ is the number of months compared between treatment and control, n = 12 in this method.

To be considered a potential control, the similarity metric between treatment and potential control must be equal to or less than 0.2. The similarity metric was calculated using the mean absolute difference of all 12 months of linearized billing data. If 25 or more matches have been identified, the lowest 25 similarity metrics are chosen the potential control group, if less than 15 potential matches have been made, the process is repeated using the secondary neighbourhood criteria selection pool (i.e. postal code). Again, if the process identifies less than 15 potential controls, the process is repeated for the third neighbourhood selection pool (i.e. feeder). At the end of the process a list of 25 potential control customers or less per treatment customer is created and used to query the NS Power internal AMI database in stage 2.

Stage 2

AMI data from the neighbourhood selection pool candidates will be aggregated to average hourly interval consumption and peak hourly interval consumption during Winter and non-Winter, weekdays and weekends, creating two sets 96 data points per customer. This aggregated AMI data is then used to calculate a new two-dimensional Euclidean distance similarity metric 'SM_{AMI}' as defined by equation (1).

The calculation is completed for each treatment customer and their respective potential control, with the ten lowest similarity metrics being used to identify the top ten control for each treatment. A top ten list is required to balance for E1 program participation performed by 3rd party consultants with access to the E1 dataset.

IV.2 Heating Classification by Phase

The heating classification methodology has changed in each Phase of the evaluation, the method used during each Phase is described below.

IV.2.1 Phase 1

Heating classification in Phase 1 was based on rate code (i.e. 02 = Non-Electric, 03 = Electric). Premises are classified as rate 02 and 03 when first registered with NS Power as a customer. These rate codes are often not re-classified when the homes primary heating source changes. With heat pump adoption alone, Nova Scotians have electrified their heating significantly thus making their rate code classification less accurate.

IV.2.2 Phase 2

To account for customers who've modified their heating source from their original rate code classification, the heating classification methodology was modified to use AMI and nearby weather station temperature data for individual premises to classify space heating types. Data was restricted

to days where the average daily temperature is below 10 °C. The more negatively correlated a customer's consumption is to temperature (i.e. consumption increases with a temperature decrease) a customer would be classified as secondary electric (-0.6<R≤-0.35) or primary electric (-0.6≤R). The model's output is simplified for the purposes of this evaluation to consider all customers as primary or secondary electric to 'electric' (i.e. R≤-0.35). Additionally, a mean consumption threshold during the top 20 consumption days of 0.5 kW or greater was required. The top 20 mean consumption metric was to avoid classifying customers with significantly low consumption during cold days regardless of correlation coefficient. Both metrics must be satisfied to be classified as electric; refer to Table 73.

Table 73: Electric Space Heating Classification Requirements

Mean load during top 20 consumption days	R≤-0.35	R>-0.35
<0.5 kW	Non-Electric	Non-Electric
≥ 0.5 kW	Electric	Non-Electric

The methodology was an improvement, however, this classification did not account for changes in heating type between pre-pilot and pilot period.

IV.2.3 Phase 3

To account for customers changing heating types between pre-pilot and pilot period, Phase 3 included a pre-pilot and pilot period evaluation of heating classification using the same methodology as in Phase 2, with the distinction of taking the difference between heating classifications to define four new heating classifications; refer to Table 74.

Table 74: Heating Classification Definition

Heating Classification	Pre-Pilot	Pilot Period
Steady Electric	Electric	Electric
Steady Non-Electric	Non-Electric	Non-Electric
Electrified	Non-Electric	Electric
De-Electrified	Electric	Non-Electric

IV.2.4 Phase 4

Phase 4 (this Phase) of the evaluation uses a similar methodology as Phase 3, with two key distinctions that improved the accuracy of the model.

1. Heating classification is used in addition to the neighborhood criteria during control group selection. Therefore, like neighborhood criteria, a control customer must have the same heating classification as their corresponding treatment customer. By controlling for heating classification, load impact by space heating type is more accurate.
2. Instead of using AMI data from all 24 hours, data for heating classification is restricted to only overnight hours (i.e. 10 PM – 5 AM). This method will ensure that a customer who reduced their space heating load during peak hours, while maintaining electric space heating during off-peak hours will continue to be classified as electrically heated. This distinction is critical in capturing the effect of the TVP price signal on those who have modified their use of space heating due to the price signal.

IV.3 Regression Model

Changes to the regression model are documented within this section with the intent to summarize the change and its justification so that future evaluations can benefit from the iterative development of the TVP evaluation.

IV.3.1 Temperature

Temperature influences customer consumption, as such the regression model used in the first Phase of the evaluation was modified to include heating degree days, refer to equations (19) and (20) taken directly from the Phase 1 and Phase 2 evaluation reports. Note that these regression models have different coefficient nomenclature than those of the Phase 4 evaluation, however the methodology remains consistent between Phase 2, 3 and 4.

Phase 1

$$Load_{i,t} = \alpha + \pi \cdot PilotPeriod_t + \gamma \cdot Treatment_i + \beta \cdot Pilot\&Treament_{it} \quad (19)$$

Phases 2, 3 and 4

$$Load_{i,t} = \alpha + \pi \cdot PilotPeriod_t + \gamma \cdot Treatment_i + \beta \cdot Pilot\&Treament_{it} + \mu \cdot PilotTreatment_{it} \cdot HDD_{it} \quad (20)$$

Where:

$\boldsymbol{Load_{i,t}}$ is the average load in kW by customer i for each peak period of 4 hours t.

$\boldsymbol{\alpha}$ is the intercept (the average demand that is independent of any of the independent variables).

$\boldsymbol{\pi}$ is the model coefficient describing the correlation between the pilot period and the average load.

$\boldsymbol{\gamma}$ is the model coefficient describing the correlation between being a treatment customer and the average load.

$\boldsymbol{\beta}$ is the model coefficient describing the correlation between being a treatment customer during the pilot period and the average load.

μ is the model coefficient describing the correlation between the $Pilot\&Treatment$, the HDD variable, and the average load. If significant, this value is included in the effect of TVP by multiplying it by the average HDD when the variable $Pilot\&Treatment$ is 1.

$\boldsymbol{PilotPeriod_t}$ is a binary variable that equals 0 during the pre-pilot period and 1 during the pilot period.

$\boldsymbol{Treatment_i}$ is a binary variable that equals 0 for control group customers and 1 for participant group customers.

$\boldsymbol{Pilot\&Treament_{it}}$ is a binary variable that equals 1 for participant group customers during the pilot period and 0 for all other cases.

$\boldsymbol{HDD_{it}}$ – Variable linked to the heating degree-day (with a balance temperature of 12 °C) value for peak period t and the weather station associated to participant i. This variable is generally the average HDD per day minus a fixed value determined by the regression.

IV.3.2 Commercial

The Commercial regression model used for Phases 1, 2, and 3 followed the same fixed effects regression framework as the Residential model, less the control participants due to poor control group match results.

In practice, the fixed effects specification was not successful in the commercial segment due to substantial heterogeneity within the commercial rate class. Differences in customer size, operating profiles, and load variability introduced instability and limited the model's ability to reliably capture treatment effects. As a result, the commercial model required additional consideration beyond the residential approach to better account for structural differences across customers and improve the robustness of the estimated impact. The two modifications include altering the regression from a fixed to mixed effects regression as well as introducing a robust standard error calibration, all of which is captured separately in Attachment V: Validation of Mixed Effects Regression.

Attachment V: Validation of Mixed Effects Regression

The NS Power commercial TVP evaluations (Phase 1 – 3)[25] has historically provided statistically insignificant results. Findings such as "statistically insignificant" can be simplified to two meanings:

1. You do not reject the null hypothesis, hence there is no effect from TVP.
2. Due to sample size and or methodological choices the power of the analysis is low, resulting in Type II error (i.e. false negative).

Sample sizes have steadily increased each Phase for TVP, which is helpful in reducing Type II error, however, sample size is not a parameter that can be increased further by this evaluation. Methodology, however, has remained relatively consistent each year and should be re-examined. Using the residential model for the commercial rate classes, perhaps for consistency seems ideal, however in practice it introduced a flaw into the analysis. One important distinction between the two rate classes (residential & commercial) is how homogeneous residential customer load profiles are compared to the heterogenous commercial customer load. Although this is not an arduous claim, evidence to support such a claim is found in the control group selection methodology continuously failing to find an adequate 1:1 match for commercial customers (refer to section 0

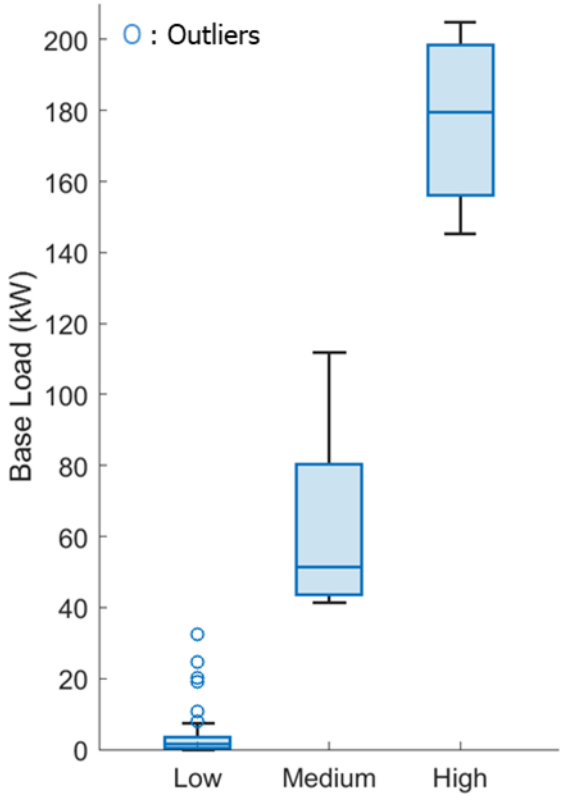
[25] NS Power, TVP EM&V Reports Phases 1 – 3 , NSEB Matter Numbers (M10703, M11267, M11823)

Control Group Selection) relative to residential customers. As such, the methodological choice to use a fixed effects regression model for commercial customers, like residential, would undoubtedly introduce significant Type II error. In the Phase 4 evaluation, the regression model was redesigned to include mixed effects, ultimately controlling for the heterogenous nature of commercial baseloads and load. Validation of this choice is provided for both the original commercial TOU and CPP rates and the new MURB TOU rate in the subsequent sections.

Commercial TOU and CPP Customers

Figure 51 illustrates the baseload heterogeneity of TVP commercial premises, where substantial differences in baseline (Low, Medium and High), associated with time-invariant variables (e.g. size of the business), can be distinguished across TVP commercial participants. Regarding this baseload heterogeneity across commercial customers, it is important to mention that a Fixed-Effect model absorbs the time-invariant differences by eliminating the heterogeneity from the analysis and assigning it to the error[26]. In contrast, a Mixed-Effect model accounts for the time-invariant differences, such as the baseload heterogeneity (Figure 51), among commercials by capturing them in the random intercept instead of error term.

Figure 51: The Baseload Heterogeneity, Classified as Low, Medium and High, across Commercial TVP Participants



[26] Frees, E. W. (2003). Longitudinal and Panel Data: Analysis and Applications for the Social Sciences. Cambridge University Press.

For commercial TOU customers during Phase 4, Figure 52(a,b) present a comparison between Fixed-Effect and Mixed-Effect based analysis. For commercial TOU customers, the Fixed-Effect model produces substantially higher residual autocorrelation than the Mixed-Effect model (Figure 52a), indicating weaker control for time-series dependence in the load data. Likewise, the Fixed-Effect model yields a noticeably larger median residual error relative to the Mixed-Effect model (Figure 52b). Examination of the residual error distributions further highlights these differences, where the Fixed-Effect model exhibits a negatively skewed distribution with a much larger median residual error (Figure 52c) than the Mixed-Effect model that produces an approximately normal and well-centered distribution with a median residual error of near zero (Figure 52d).

Figure 52: (a) A Comparison of Residual Autocorrelation and (b) Median of Residual Error between Fixed Effect and Mixed Effect Modelling Approaches for Commercial-TOU Customers Evaluated for Load Reduction, along with the Residual Error Distribution Associated with (c) Fixed Effect Modelling and (d) Mixed-Effect Modelling

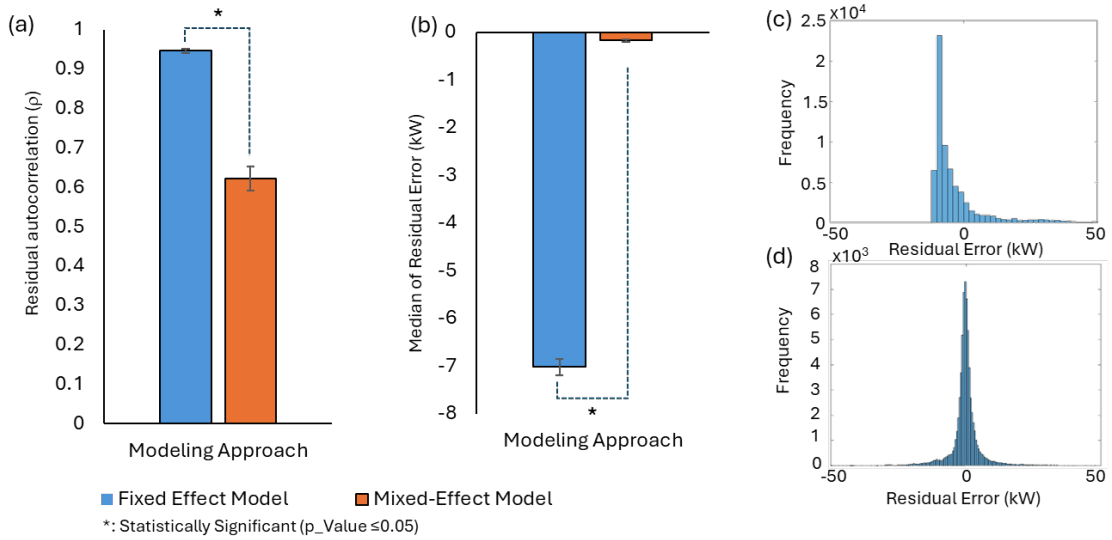
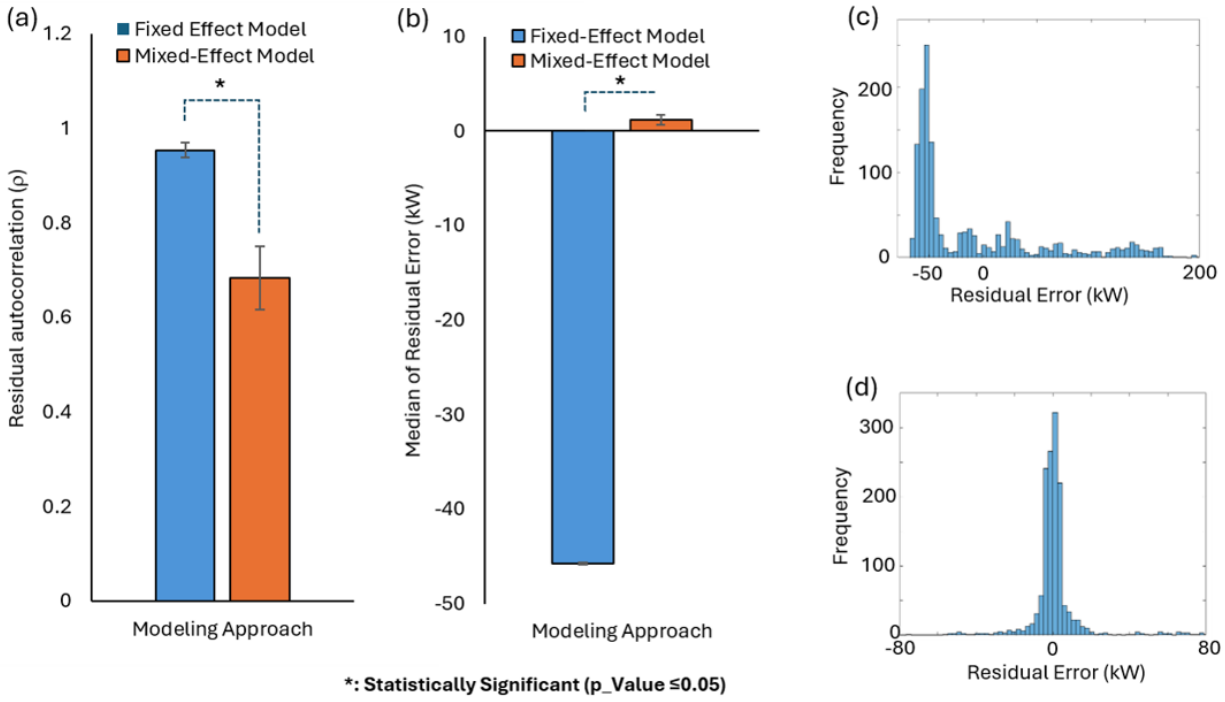


Figure 53(a,b) compare residual autocorrelation (ρ) and the median residual error (RE) between Fixed-Effect and Mixed-Effect modeling approaches used to evaluate load reduction by commercial CPP participants during CPP events in Phase 4. The Mixed-Effect model exhibits substantially lower residual autocorrelation (Figure 53a), indicating the suitability of Mixed Effect modeling to account for serial (time-series) variability in the Commercial-CPP load data. In addition, the Mixed-Effect model results in a significantly smaller median residual error of ~2.5 kW of load reduction compared to the Fixed-Effect model, which exhibits a median residual error of ~−45 kW, corresponding to a load increase (Figure 53b). Furthermore, the Fixed-Effect model exhibits a negatively skewed distribution (Figure 53c), while the Mixed Effect model shows an approximately normal and well-centered distribution with a median residual error of near zero (Figure 53c).

Figure 53: (a) A Comparison of Residual Autocorrelation and (b) Median of Residual Error between Fixed Effect and Mixed Effect Modelling Approaches for Commercial-CPP Customers Evaluated for Load Reduction during CPP Events, along with the Residual Error Distribution Associated with (c) Fixed Effect Modelling and (d) Mixed-Effect Modelling



Given the baseload heterogeneity, time-series (hourly) load data and the business type variability that leads to heterogeneous response patterns across commercial customers, these results suggest that the Mixed-Effect model provides a more balanced error structure and improved model fit for commercial TOU and CPP load response analysis. Thus, a Mixed-Effect model was used as this is a more statistically appropriate approach for assessing Commercial CPP and TOU impacts.

MURB TOU Customers

Unlike the commercial TOU and CPP rates, MURB TOU has not yet been evaluated using the fixed effects regression model. As such additional analyses are provided within in order to validate the choice of a mixed effects regression model (with control group) for the MURB TOU Tariff.

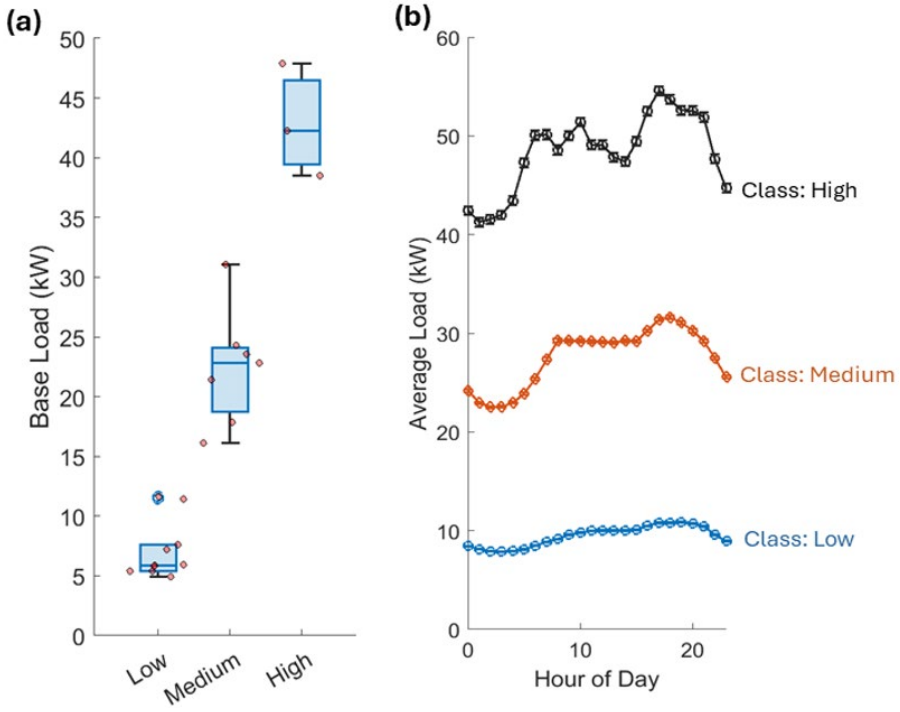
Baseload Heterogeneity Analysis

The baseline segmentation analysis indicates substantial heterogeneity in electricity consumption patterns across participating MURBs, particularly with respect to Baseload levels. Based on these characteristics, MURBs can be classified into three distinct baseline consumption classes, Low, Medium, and High, each exhibiting statistically meaningful differences in Baseline electricity consumption.

Figure 54a illustrates the distribution of baseload (kW) across the three classes. As shown in Figure 54a, baseload levels range from 5 to 8 kW for the *Low* class, 12 to 31 kW for the *Medium* class, and 38 to 47 kW for the *High* class. Furthermore, Figure 54b shows profound differences in load profile

between these classes. The clear separation in both baseload load profile confirms the presence of a substantial heterogeneity among MURB customers, which has important implications for accuracy of program impact estimation and model specification.

Figure 54: MURB TOU Classified into Three Classes (Low, Medium and High) in Terms of (a) Baseload (kW) and (b) Load Profile, Indicating Substantial Heterogeneity among MURB Customers



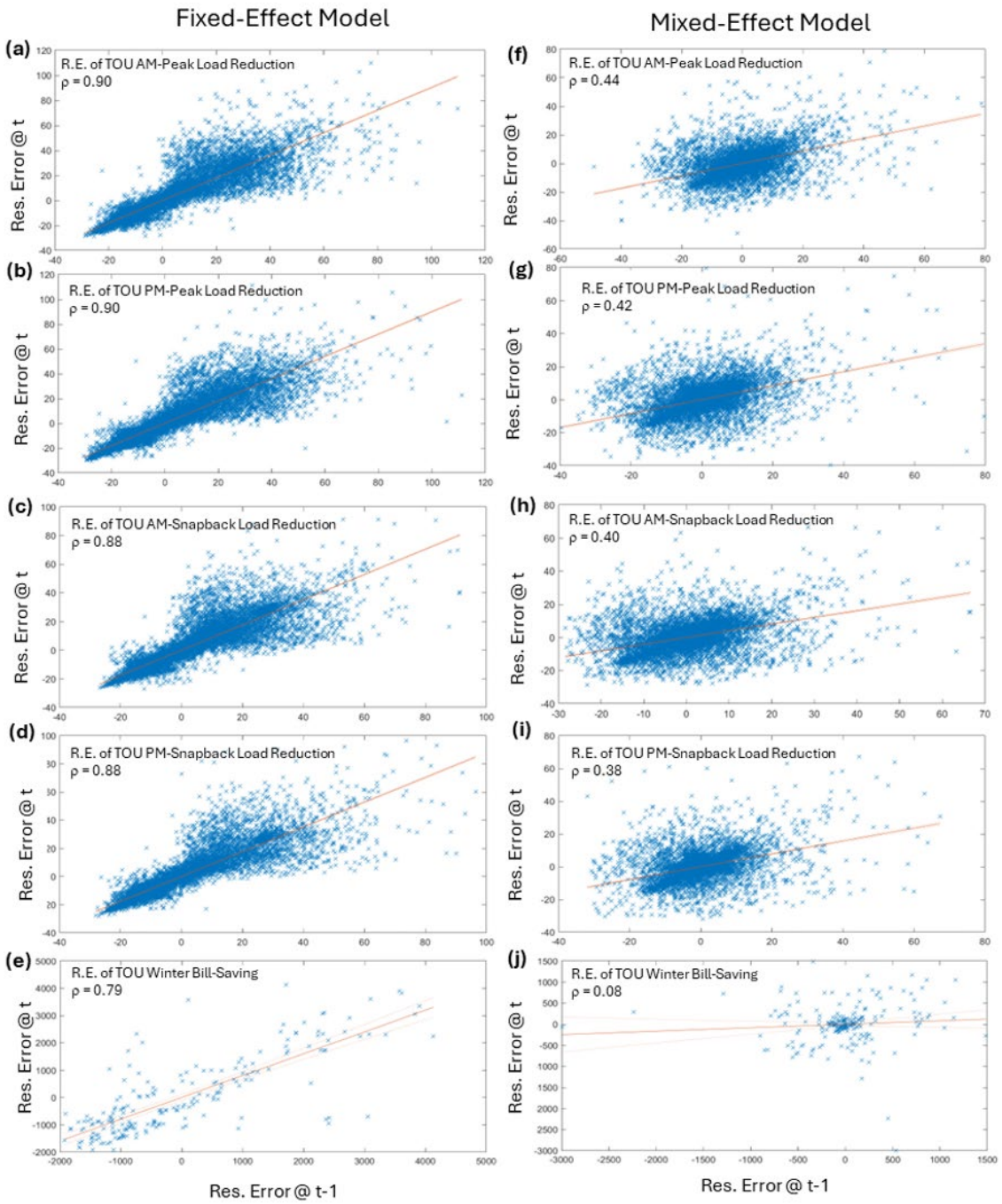
Residual Diagnostics for Fixed- vs. Mixed-Effect Modeling Approaches

It is important to note that a Fixed-Effect model absorbs the time-invariant differences, such as Baseload heterogeneity across MURBs, by eliminating it from the analysis and assigning it to the error[27]. Thus, under a Fixed-Effect Model, TOU impact estimates rely exclusively on within-premise variation over time, with baseline heterogeneity effectively removed. In contrast, a Mixed-Effect model accounts for the Baseload heterogeneity among MURBs by capturing them in the random intercept instead of error term.

Considering the substantial differences in baseline load across MURBs (Figure 54), a Mixed-Effects modeling approach appears more suitable for estimating treatment impacts under the TOU-MURB program. To assess the relative performance of the models, residual diagnostics were conducted for both Fixed-Effects and Mixed-Effects models, with a focus on comparing residual error (RE) autocorrelation (ρ) between the two approaches (Figure 55).

[27] Frees, E. W. (2003). Longitudinal and Panel Data: Analysis and Applications for the Social Sciences. Cambridge University Press.

Figure 55: The Residual Error (RE) Autocorrelation (r) Resulted from the Fixed-Effect Model (a–e) and the Mixed-Effect Model (f–j) for Evaluating (a, f) AM-Peak Load Reduction, (b, g) PM-Peak Load Reduction, (c, h) AM-Snapback Effect, (d, i) PM-Snapback Effect, and (e, j) Bill-Saving during Winter for TOU-MURBs

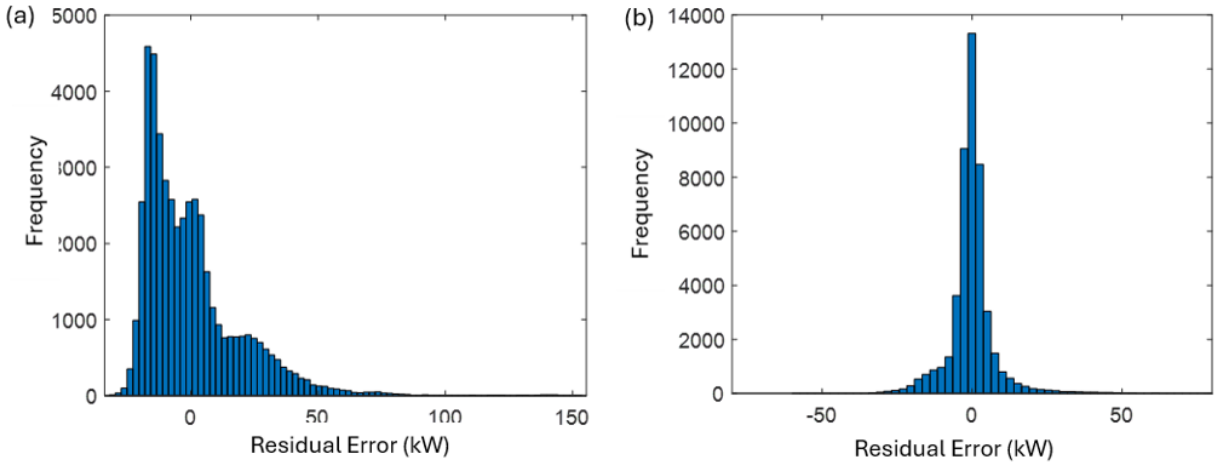


The RE autocorrelation (r) was evaluated based on the residual serial correlation between RE at time (*t*) and the RE at the previous time (*t-1*). Figure 55 presents the estimated residual serial correlation for the Fixed-Effect model (Figure 55a – e) and Mixed-Effect model (Figure 55f – j), where the models

were applied for estimating the Load-Reduction and Bill-Saving during peak and snapback hours, and during Winter, respectively. Figure 55 indicates that the magnitude of residual errors produced by the Fixed-Effects models (Figure 55a – e) is consistently larger than that observed for the corresponding Mixed-Effect models (Figure 55f – j).

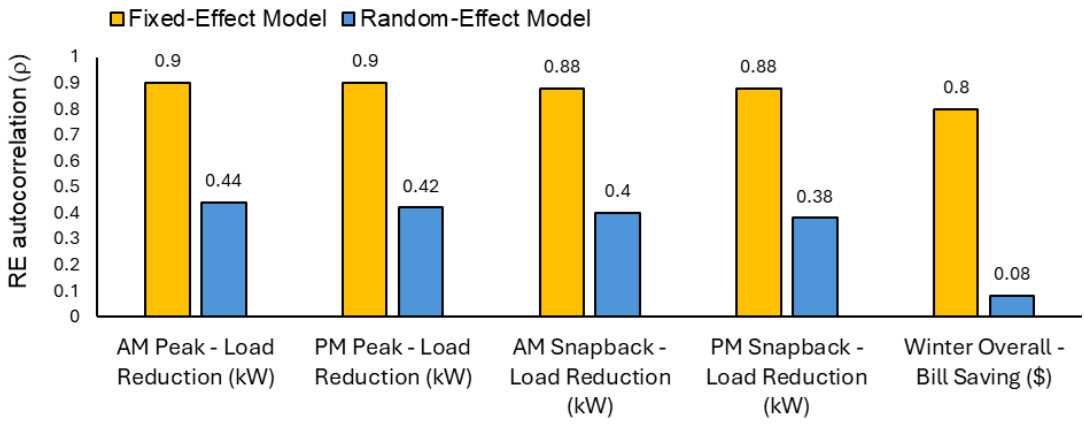
Furthermore, the Fixed-Effect model exhibits a negatively skewed distribution (Figure 56a), while the Mixed Effect model shows an approximately normal and well-centered distribution with a median residual error of near zero (Figure 56b).

Figure 56: Residual Error Distribution Associated with (a) Fixed Effect Modeling and (b) Mixed-Effect Modeling



In addition, the Mixed-Effect model exhibits substantially lower RE autocorrelation (ρ) relative to the Fixed-Effects model, as illustrated in Figure 57. This comparison implies that the influence of the Baseload heterogeneity among MURBs leaks into residuals and becomes serially correlated when the Baseload heterogeneity is excluded by the Fixed-Effect model. In contrast, the Mixed-Effect model captures the Baseload heterogeneity into random intercepts, resulting in decreased RE autocorrelation.

Figure 57: A Comparison of the Residual Autocorrelation between Fixed-Effect Model and Mixed-Effect Model for TOU-MURBs evaluated for the Load Reduction during Morning Peak (AM-Peak) hours, Evening Peak (PM-Peak) hours, Morning Snapback (AM-Snapback) and Evening-Snapback (PM-Snapback) hours, as well as for the Bill Saving ($) during Winter



Given the small sample size of MURBs (n = 10), the substantial heterogeneity in Baseline electricity consumption across MURBs (Figure 54), and the supporting results from the comparison of Fixed-Effect and Mixed-Effect models (Figure 55 & Figure 57), the Mixed-Effect modeling approach is the preferred model for estimating the impact of TOU-MURBs pilot program.

Robust Margin of Error

When TVP load impact was estimated using the DiD analysis, the residual errors can be autocorrelated. If residual autocorrelation is not adjusted for, the standard error will be underestimated. As such, it is necessary to adjust the 90% MoE as follows:

$$MoE\ (90\%)_{adj} = z.\frac{SE}{\sqrt{1-\rho^2}} \tag{21}$$

Where MoE $(90\%)_{adj}$ is adjusted MoE at 90% confidence level, z value is the critical value derived from the standard normal distribution (z-distribution) and is approximately 1.645, *SE* is the standard error, and ρ is the first-order residual autocorrelation coefficient which is calculated as follows:

$$\rho = \frac{\sum_{t=2}^{n}(e_t - \bar{e}\,)(e_{t-1} - \bar{e}\,)}{\sum_{t=1}^{n}(e_t - \bar{e}\,)^2} \tag{22}$$

Where *e* is the residual error, *t* is time, $\bar{e}$ is the mean of residual errors, and *n* is the number of data points.

Furthermore, the variance of residual errors may change across the time-load data, instead of being spread out. This results in heteroskedasticity in model predictions, which is addressed through calculating robust MoE (90%) as follows:

$$MoE(90\%)_{robust} = z.\frac{SE_{robust}}{\sqrt{1-\rho^2}} \tag{23}$$

Where SE_{robust} is the robust standard error and is obtained as:

$$SE_{robust} = \sqrt{c^T.V_{robust}.c} \tag{24}$$

Where *c* is the coefficient vector corresponding to the estimates in the model, c^T is the transpose of coefficient vector, and V_{robust} is the robust covariance matrix of the coefficients.

Attachment VI: Control Group Selection Non-Load Variables

Table 75: Average of Residential Control, Treatment and Nova Scotia Population Non-Load Baseline Characteristics (Median Income, Average Residents, Year Built, Living Space)

Metric	Rate	Treatment	Control	Population
Median Income[28]	**CPP**	$ 88,813	$ 85,986	$ 85,143
	TOU	$ 88,496	$ 86,853	
Average Residents per Household[28]	**CPP**	2.372	2.344	2.384
	TOU	2.371	2.355	
Year Built[29]	**CPP**	1979	1978	1979
	TOU	1979	1977	
Living Space (ft^2)[29]	**CPP**	1,762	1,728	1,540
	TOU	1,755	1,718	
Note: This table presents the average of the median income and average of the average residents per household per postal code.				

Table 76: Residential Control, Treatment and Nova Scotia Population Non-Load Baseline Characteristics (Housing Style)

House Style[29]	Customer count by group			Percent by group		
	Treatment	Control	Population	Treatment	Control	Population
1 Storey	2,457	2,653	156,145	33.9	36.6	40.7
2 Storey	1,927	1,818	75,435	26.6	25.1	19.7
1.5 Storey	864	799	54,647	11.9	11.0	14.3
Split Entry	747	777	31,987	10.3	10.7	8.3
Manufactured Home	117	180	19,373	1.6	2.5	5.1
Unknown	0	0	12,588	0.0	0.0	3.3
2 Storey Semi Detached	368	268	9,401	5.1	3.7	2.5
Split Level	199	207	8,511	2.7	2.9	2.2
2 Storey Townhouse	236	196	3,743	3.3	2.7	1.0
1 Storey Semi Detached	95	63	3,332	1.3	0.9	0.9
1 Storey Duplex	57	65	2,212	0.8	0.9	0.6
2 Storey Duplex	65	67	1,712	0.9	0.9	0.4
2.5 Storey	32	41	1,114	0.4	0.6	0.3

[28] Median Income & Average Household Residents data, Source: Environics Analytics 2024 modelling of Statistics Canada FSA income survey results to 6-digit postal code, mapped to control and treatment using 6-digit postal code.

[29] Property Valuation Services Corporation (PVSC), mapped by nearest property using latitude and longitude radii calculation, where "House Style" is limited to non-MURB housing. Note: This does not indicate MURB participants do no exist in TVP.

Attachment VI: Control Group Selection Non-Load Variables

House Style[29]	Customer count by group			Percent by group		
	Treatment	Control	Population	Treatment	Control	Population
1.5 Storey Semi Detached	11	13	1,085	0.2	0.2	0.3
1 Storey Townhouse	26	23	750	0.4	0.3	0.2
3 Storey	16	21	365	0.2	0.3	0.1
1.5 Storey Duplex	0	3	138	0.0	0.0	0.0
Additon	0	1	132	0.0	0.0	0.0
1 Storey Triplex	6	4	120	0.1	0.1	0.0
2 Storey Triplex	7	10	113	0.1	0.1	0.0
3 Storey Townhouse	1	1	76	0.0	0.0	0.0
2.5 Storey Townhouse	7	7	61	0.1	0.1	0.0
1 Storey Quadruplex	3	8	60	0.0	0.1	0.0
1.5 Storey Townhouse	0	0	58	0.0	0.0	0.0
3 Storey Semi Detached	3	10	56	0.0	0.1	0.0
2.5 Storey Semi Detached	1	4	43	0.0	0.1	0.0
2 Storey Quadruplex	3	3	31	0.0	0.0	0.0
2.5 Storey Duplex	0	1	15	0.0	0.0	0.0
3 Storey Triplex	0	1	12	0.0	0.0	0.0
1.5 Storey Triplex	0	0	8	0.0	0.0	0.0
2.5 Storey Triplex	0	0	6	0.0	0.0	0.0
3 Storey Duplex	0	1	6	0.0	0.0	0.0
3 Storey Quadruplex	0	2	5	0.0	0.0	0.0
2.5 Storey Quadruplex	2	3	4	0.0	0.0	0.0
1.5 Storey Quadruplex	0	0	1	0.0	0.0	0.0

Attachment VII: Board Directives and Consensus Agreement Commitments

NS Power has reviewed all Nova Scotia Energy Board (NSEB) directives pertinent to the TVP Phase 4 EM&V report and has responded to, using reference to previously filed content and/or additional analyses as required.

Demand Response Overlap between NS Power and E1

In its Decision on E1's 2026 DSM Extension Application (M12249), the Board provided:

> The Board agrees that concerns about E1's demand response programs are better addressed in its consultations and upcoming application for approval of its five-year DSM Plan. That said, the Board notes that E1 should be fully prepared to address the questions raised in this proceeding about potential overlap with NS Power's Critical Peak Pricing Program and the targeting of constrained areas of the transmission and distribution system in its application. If it fails to adequately address these issues, this may complicate the approval of its DSM Plan. The Board expects NS Power to cooperate fully with E1 in exploring these issues.

To evaluate these questions of potential overlap, an evaluation was completed where a subset of participants who were enrolled in both Eco Shift and Critical Peak Pricing rates received a coordinated set of event calls from both programs and were segregated from the broader pilot to evaluate any potential incremental load shift above that which is attributable to Critical Peak Pricing alone. The analysis was further extended to participants who were enrolled in both Eco Shift and Time-of-Use rates. NS Power has provided the interactive load effects of Eco Shift and TVP (both TOU and CPP) in Sections 3.1.1, 4.1.1, 5.1.1, and 6.1.1. A discussion on the Methodology is provided in Section 2.1.1 and in Attachment III: Methodology.[30]

[30] M12249 – Board Decision, 326722, page 26, para. 65. December 22, 2025.

Coincidence of Critical Peak Events and System Margin

In its Decision and Order on the Year Three (2023/24) Evaluation Report (Year Three Report) in M11823, the Board provided:

> NS Power agreed with Synapse that system margin forecasts may be a better indicator of when to call a CPP event. The Board directs NS Power to provide an analysis of the correspondence of system margin forecasts and CPP events in the Year 4 report, providing the days with a forecast of low system margin and the forecast system margin for the days when a CPP event was called. Further, NS Power is directed to work with stakeholders to refine its methods of estimating load reductions achieved through the TVP tariffs.[31]

Upon analysis of historical forecast system margin during the Phase 4 Winter, the system margin forecast during CPP events was 91.6 percent less than during all other non-CPP event hours between 7 – 11 AM and 5 – 9 PM. The dates in which system margin was forecast to be low (≤ 50 MW), and whether this correlated with a scheduled Critical Peak Event during the 2024/25 Winter Season (i.e. Phase 4) is provided in Table 77.

Table 77: Dates and Times of Low Forecast System Margin and Whether a Critical Peak Event was Scheduled during the 2024/25 Winter Season

Period of Low Forecast System Margin		During Scheduled Critical Peak Event
Date	Hour Start	Yes / Cancelled / No
2024-12-04	17:00	Yes
2024-12-04	18:00	
2024-12-04	19:00	
2024-12-04	20:00	
2024-12-15	17:00	Yes
2024-12-15	18:00	
2024-12-15	19:00	
2024-12-15	20:00	
2024-12-20	7:00	Yes
2024-12-20	8:00	
2024-12-20	9:00	
2024-12-20	10:00	
2024-12-22	17:00	Yes
2024-12-22	18:00	
2024-12-22	19:00	
2024-12-22	20:00	
2024-12-23	7:00	Yes
2024-12-23	8:00	
2024-12-23	9:00	
2024-12-23	10:00	
2024-12-23	17:00	Yes

[31] M11823 – Board Decision and Order, 316514, page 5. October 31, 2024.

Attachment VII: Board Directives and Consensus Agreement Commitments

Period of Low Forecast System Margin		During Scheduled Critical Peak Event
Date	**Hour Start**	**Yes / Cancelled / No**
2024-12-23	18:00	
2024-12-23	19:00	
2024-12-23	20:00	
2025-01-21	17:00	Yes
2025-01-21	18:00	
2025-01-21	19:00	
2025-01-21	20:00	
2025-01-22	7:00	Yes
2025-01-22	8:00	
2025-01-22	9:00	
2025-01-22	10:00	
2025-02-02	17:00	Yes
2025-02-02	18:00	
2025-02-02	19:00	
2025-02-02	20:00	
2025-02-05	17:00	Yes
2025-02-05	18:00	
2025-02-05	19:00	
2025-02-05	20:00	
2025-02-06	7:00	Yes
2025-02-06	8:00	
2025-02-06	9:00	
2025-02-06	10:00	
2025-03-04	7:00	Yes
2025-03-04	8:00	
2025-03-04	9:00	
2025-03-04	10:00	
2025-03-10	7:00	Yes
2025-03-10	8:00	
2025-03-10	9:00	
2025-03-10	10:00	
2025-03-11	7:00	Yes
2025-03-11	8:00	
2025-03-11	9:00	
2025-03-11	10:00	
2024-12-10	17:00	Cancelled Event
2024-12-10	18:00	
2024-12-10	19:00	
2024-12-10	20:00	
2025-02-12	7:00	Cancelled Event
2025-02-12	8:00	
2025-02-12	9:00	

Attachment VII: Board Directives and Consensus Agreement Commitments

Period of Low Forecast System Margin		During Scheduled Critical Peak Event
Date	Hour Start	Yes / Cancelled / No
2025-02-12	10:00	
2025-02-12	17:00	Cancelled Event
2025-02-12	18:00	
2025-02-12	19:00	
2025-02-12	20:00	
2024-11-02	16:00	No
2024-11-02	17:00	
2024-11-02	18:00	
2024-11-02	19:00	
2024-11-02	20:00	
2024-11-02	21:00	
2024-11-03	16:00	No
2024-11-03	17:00	
2024-11-03	18:00	
2024-11-03	19:00	
2024-11-03	20:00	
2024-11-04	7:00	No
2024-11-04	8:00	
2024-11-04	9:00	
2024-11-04	15:00	No
2024-11-04	16:00	
2024-11-04	17:00	
2024-11-04	18:00	
2024-11-04	19:00	
2024-11-04	20:00	
2024-11-04	21:00	
2024-11-04	22:00	
2024-11-24	17:00	No
2024-11-24	18:00	
2024-11-26	7:00	No
2024-12-16	7:00	No
2024-12-23	16:00	No
2024-12-23	21:00	No
2024-12-23	22:00	
2024-12-24	7:00	No
2024-12-24	8:00	
2024-12-24	9:00	
2024-12-24	17:00	No
2024-12-24	18:00	
2025-01-13	16:00	No
2025-01-13	17:00	
2025-01-13	18:00	

Attachment VII: Board Directives and Consensus Agreement Commitments

Period of Low Forecast System Margin		During Scheduled Critical Peak Event
Date	Hour Start	Yes / Cancelled / No
2025-01-14	17:00	No
2025-01-17	6:00	No
2025-01-17	7:00	
2025-01-17	8:00	
2025-01-17	9:00	
2025-01-17	10:00	
2025-01-17	16:00	No
2025-01-17	17:00	
2025-01-17	18:00	
2025-01-18	6:00	No
2025-01-18	7:00	
2025-01-18	8:00	
2025-01-18	9:00	
2025-01-21	16:00	No
2025-01-21	21:00	No
2025-01-23	7:00	No
2025-01-29	7:00	No
2025-01-29	8:00	
2025-01-29	9:00	
2025-01-29	16:00	No
2025-01-29	17:00	
2025-01-29	18:00	
2025-01-29	19:00	
2025-01-29	20:00	
2025-02-06	5:00	No
2025-02-06	6:00	
2025-02-08	18:00	No
2025-02-09	5:00	No
2025-02-10	7:00	No
2025-02-11	7:00	No
2025-02-11	8:00	
2025-02-12	21:00	No
2025-02-13	7:00	No
2025-02-13	8:00	
2025-02-13	9:00	
2025-02-22	18:00	No
2025-02-22	19:00	
2025-02-22	20:00	
2025-03-11	6:00	No

Performance Assessment on General Service Class Customers

In its Decision and Order on the Year Three Report (M11823), the Board provided:

> The Year 3 Report notes that commercial customer enrollment in the TVP is low, making a robust evaluation of this customer group problematic. The Board directs NS Power to complete a performance assessment of the General Service Class customers, as described in Synapse's evidence, evaluating the extent that bills increase as they shift load from on-peak hours to off-peak hours. It is expected that this assessment will identify whether the demand charge increases the electricity bills for these participants. If the assessment finds that the demand charge results in higher bills to the commercial class customers shifting their load from on-peak to off-peak, NS Power is to assess removal of the demand charge, as well as any other changes, which could incentivize the participation of the commercial rate class customers in the TVP Program. The Board directs NS Power to provide the outcome of this assessment and potential tariff changes to stakeholders during an engagement session and to the Board in the Year 4 Report.
>
> The Board finds that if NS Power's assessment determines the demand charge is not a deterrent and/or the cause of lower commercial customer enrollment in the TVP, NS Power is directed to review and improve its customer engagement with commercial rate class customers and to revisit the incentive structure for the commercial TVP tariffs so that commercial operations and load shifting are not mutually exclusive.[32]

NS Power completed this analysis and presented the outcomes to TVP stakeholders at Technical Session 2, held April 7, 2025. Technical Session 2 materials are provided as Appendix E, Attachments 4 and 5 as a part of this filing.[33] In its analysis, NS Power found that approximately 44 percent of General Class customers have peak consumption that corresponds to the same peak periods identified in the General TOU Tariff. As such, shifting load away from TOU peak periods could reduce demand and further lower the customer's bill. Additionally, as outlined within the body of this Report, NS Power's evaluation has identified a statistically significant load shift in the commercial TOU rate classes (Table 34), especially in the General rate class (Figure 32b), commercial operations and load shifting are no longer mutually exclusive. This finding is the result of a key methodological improvement (i.e. random intercept / mixed effects regression) quantified in equations (14), (15), (16), and (17) and validated in Attachment V: Validation of Mixed Effects Regression.

Reporting on Small Business Characteristics that Enable Load Shifting

As part of its 2024 TVP Consensus Agreement, the Company committed to:

> h. Reporting back to stakeholders on changes that could be made to help customers determine whether they will benefit from TVP, TOU and CPP options. This report will be provided by NS Power and include the following:

[32] M11823 – Board Decision and Order, 316514, page 6.

[33] Please refer to pages 5-8 of Appendix E, Attachment 4.

i. Summary of the general load characteristics of small business customers that may enable a small business customer to shift load in response to TVP, CPP, or TOU rates.

ii. Information on commercial/small business customer recruitment tele-marketing or on-site contact with the customer (including parent company staff), as may be necessary. NS Power does not currently collect complete SIC Code data for all customers. However, NS Power agrees that this type of information would be valuable and will explore analytical opportunities that could allow customers to be classified by business sector. NS Power will provide an update on these efforts in the report.

iii. The recruitment tactics for contacting business customers for Years 4 and beyond have not yet been determined; however, should outcall be utilized, NS Power will provide the script.

iv. NS Power will provide a summary of specific reasons why customers are reluctant to participate, followed by an evaluation of the pilot tariff to see if changes can address some of the concerns, (i.e., create successful recruitment).[34]

In its Decision and Order on the Year Three Report (M11823), the Board further provided:

> NS Power agreed with Synapse's recommendation to improve customer education and to continue collecting participant feedback. As part of the 2024/25 Areas of Focus, NS Power will develop and provide stakeholders with an analysis of commercial class customer characteristics that have the capacity in the TVP to reduce load at peak periods.[35]

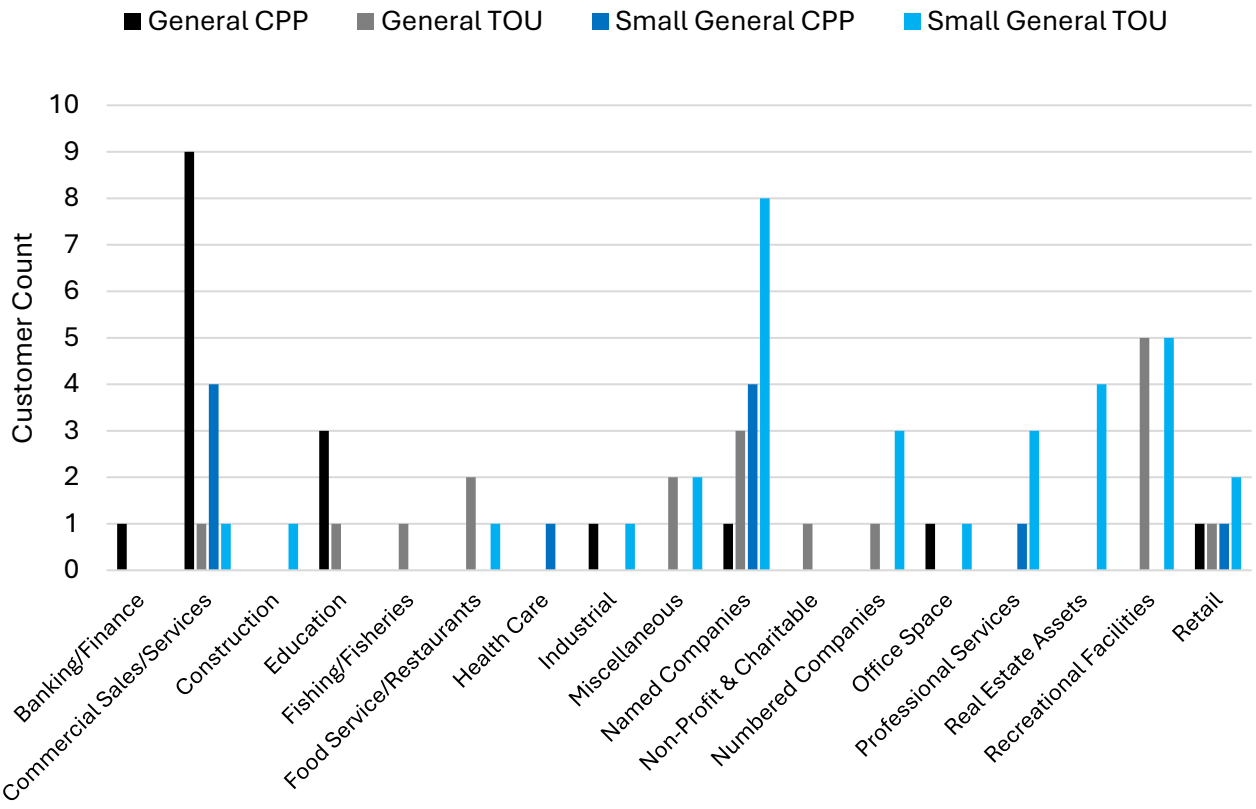
In relation to the summary of general load characteristic, load shifting (kW per customer) in both TOU and CPP commercial rates was primarily driven by the General rate class (Figure 32b & Figure 38b). This rate characteristic, which is determined by the business' scale of energy consumption, is the only characteristic found to date which impacts load shifting response. Based on the business verticals used to classify customers[36], an estimated breakdown of participating commercial customers by TVP Tariff and business vertical is provided in Figure 58.

[34] M11822 – TVP Consensus Agreement (Appendix A), pages 8-9. July 31, 2024.

[35] M11823 – Board Decision and Order, 316514, page 5.

[36] TVP Tariff Pilot –Technical Session 2, April 7, 2025, Slide 28.

Figure 58: Estimated Business Vertical Classification by TVP Tariff



Note that individual business vertical sample sizes are too small to provide statistically relevant load reduction estimates by business vertical. Additionally, the classification machine learning algorithm created by NS Power to provide such insight is still under development and provides no insight for "Named" (e.g. John Smith Industries) or "Numbered" (e.g. 1234567 Nova Scotia Limited). That said, NS Power will continue to monitor business verticals and improve its internal methods for classifying business customers and will report in more detail when TVP enrolment and classification methodologies provide sufficient sample sizes. As it stands based on this evaluations results, the General rate class, regardless of business vertical, demonstrates the current best area of focus for commercial customers (refer to Figure 32b & Figure 38b).

Further details were provided as part of Technical Session 2 (held on April 7, 2025). Technical Session 2 materials are provided as Appendix E, Attachments 4 and 5 to this Report.[37] Commercial customer marketing and recruitment materials are provided as Appendix C: Marketing and Recruitment.

[37] Please refer to Appendix E, Attachment 4, pages 18-28 and Appendix E, Attachment 5, pages 2-3.

Review of Marketing and Communication Efforts

In its Decision and Order on the Year Three Report (M11823), the Board provided:

> Narrative Research conducted a customer survey, which highlighted residential customers' dissatisfaction regarding bill savings. Synapse recommended NS Power analyze the differences in satisfaction among the tariffs and demographics and find improvements in communication with customers, particularly about bill savings. NS Power indicated that there will be a review of marketing and communication efforts with stakeholders through the pricing innovation process. The Board believes it is important that NS Power adequately communicate with the Pilot participants to set their bill savings expectations appropriately to ensure the Pilot can maintain enrollment, produce high-quality results and protect the trust of NS Power customers. NS Power is directed to report on the review of its marketing and communication efforts and its planned changes, informed by stakeholders through the pricing innovation process, in the Year 4 Report.[38]

For residential customers, NS Power equipped Customer Care agents with a purpose-built estimation tool to support inbound customer inquiries about TVP. When customers called to ask how time-varying rates might affect their bill, Customer Care representatives could generate estimated bill comparisons across available rate options (TOU & CPP) based on their energy usage profile and typical load shifting behaviour. This allowed agents to provide clear, data-driven guidance on potential savings or cost impacts, helping residential customers make informed decisions without requiring in-depth technical analysis or follow-up engagement.

NS Power engaged commercial business customers on the TVP program through a coordinated approach that combined relationship management with advanced analytics. Key Account Managers acted as the primary liaison between business customers and Nova Scotia Power, helping customers understand TVP, gathering operational context, and communicating objectives and considerations. Detailed analysis was then carried out by the data analytics team, who evaluated interval load data to model load-shifting opportunities, peak effects, and estimated bill impacts under different rate scenarios. The resulting metrics and savings estimates enabled customers to clearly assess which rate best aligned with their operational profile.

Please refer to Appendix C which provides the marketing, recruitment, and communication efforts for the 2024/25 Season. NS Power reviewed its planned marketing and recruitment efforts with TVP Stakeholders as part of Technical Session 1 (held on March 3, 2025). Technical Session 1 materials are provided as Appendix E, Attachments 3 and 4 to this Report.[39]

Other Board Directives and Consensus Agreement Commitments

Across the 2024 Consensus Agreement, Year Three Report (M11823), 2024/25 TVP Application (M11822), and other proceedings, other Board directives and commitments have been made. Throughout the 2024/25 TVP Season, the Company reviewed several of these items through NS Power's pricing innovation process and stakeholder consultative sessions. As part of the Company's October 1, 2025 Submission seeking Board approval to temporarily modify the TVP Pilot for the

[38] M11823 – Board Decision and Order, 316514, pages 5-6.

[39] Please refer to Appendix E, Attachment 3, pages 32-43 and 48-60, and Appendix E, Attachment 4, pages 38-41 and 46-47.

Attachment VII: Board Directives and Consensus Agreement Commitments

2025/26 Season (M12499), NS Power provided an update on the status of these directives and commitments. In its letter on NS Power's December 2025 Year Four Report extension request (M12499), the Board provided:

> The Board approves NS Power's request to extend the filing date of the TVP 2024/25 (Year Four) EM&V report to June 30, 2026, or earlier if the Company is able to do so. The Board also approves the deferral of the outstanding Board directives and Consensus Agreement commitments to future Technical Sessions or the Year Four EM&V report. However, for greater certainty, NS Power is directed to report on the status of these directives and Consensus Agreement commitments when it files its Year Four EM&V report.[40]

NS Power has provided an update on the status of these directives as Attachment 1 to the cover letter for this Report.

[40] M12499 – Board Letter, 326792, page 2. December 23, 2025.