Nova Scotia Energy Board

IN THE MATTER OF *The Public Utilities Act,* R.S.N.S. 1989, c.380, as amended

2025 Load Forecast Report

NS Power

June 27, 2025

REDACTED

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1.0 EXECUTIVE SUMMARY

In accordance with the Nova Scotia Wholesale Electricity and Renewable to Retail Market Rules, Nova Scotia Power Incorporated (NS Power, the Company) is required to provide the Nova Scotia Energy Board (NSEB, Board) with its 10-year energy and demand forecast by the end of April each year for the 10-year period beginning in the following January (Load Forecast).

The 2025 Load Forecast provides an outlook on the energy and peak demand requirements of in-province customers for the period 2025 to 2035. In addition, it describes the considerations, assumptions, and methodology used in the preparation of the forecast. The Load Forecast provides the basis for the planning and overall operating activities to serve customer load.

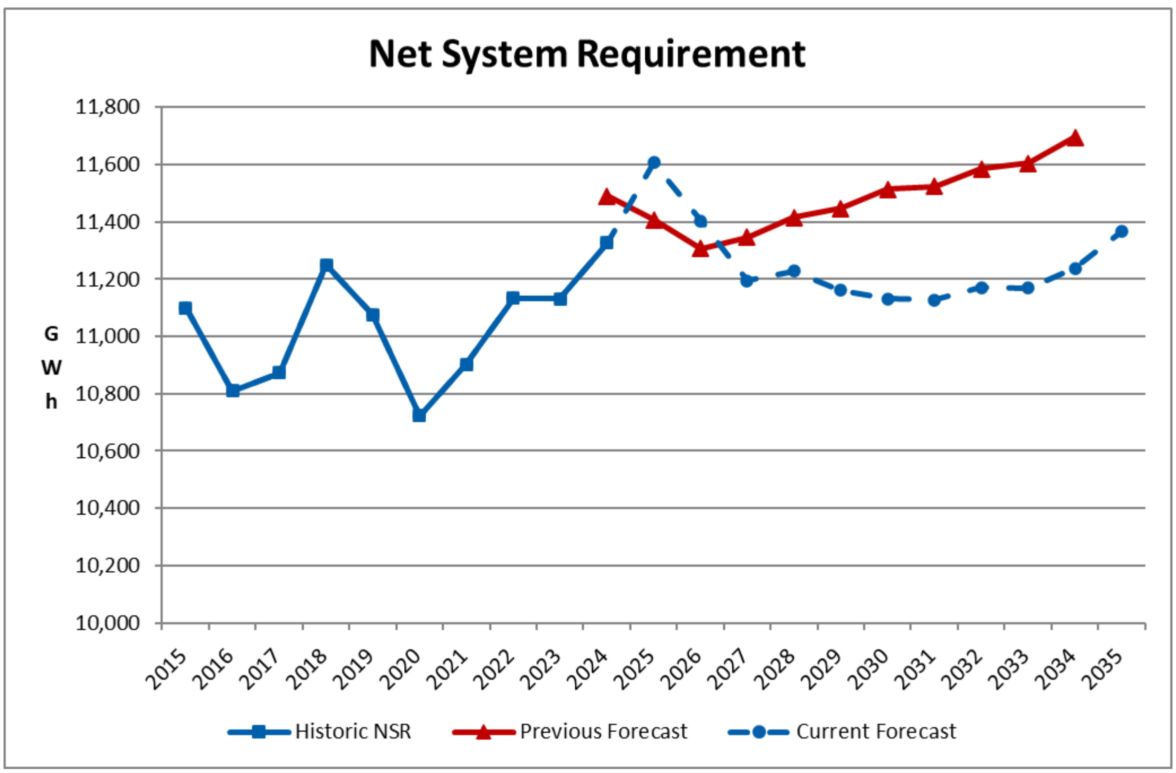
The Load Forecast is based on analyses of sales history, weather, end-use saturations and efficiencies, economic indicators, customer surveys, technological and demographic changes in the market, and the availability of other energy sources.

As with any forecast, there is a degree of uncertainty around actual future outcomes. In electricity forecasting, much of this uncertainty is due to the impact of variations in weather, energy efficiency program activities, the health of the economy, government policy, the impact of electrification, changes in large customer loads, the number of electric appliances and end-use equipment installed, and changes in technology.

NS Power continues to use and refine Statistically Adjusted End-Use (SAE) models to forecast load for the residential and commercial rate classes. The SAE models explicitly incorporate end-use energy intensity projections into the Load Forecast. End-use energy forecasts derived from the residential and commercial SAE models are then combined with an econometric-based industrial forecast and customer specific forecasts for NS Power's large customers to develop an energy forecast for the province, also referred to as the Net System Requirement (NSR).

Compared to the 2024 Load Forecast, the 2025 Load Forecast shows increased net system requirement in the near term due to a change in forecast for Renewable to Retail (RTR) sales. Mid- to long-term growth is lower in the 2025 Load Forecast, driven by reduced estimates for Electric Vehicle (EV) sales, increased sales through the RTR market, and increased behind the meter solar, offsetting continued customer growth and continued electrification of space and water heating. In the long term, energy sales will also be reduced by Demand Side Management (DSM) initiatives and natural energy efficiency improvements outside structured DSM programs. The net result is a forecast average annual decrease of 0.2 percent between 2025 and 2035. Annual historic and forecast NSR are shown below in **Figure 1.**

Figure 1: Historical and Predicted Annual Net System Requirement



In addition to annual energy requirements, NS Power forecasts system peak demand. Customer growth, electrification of heating and increased EV sales will increase the peak, while DSM and DR activities will reduce the peak. Compared to 2024, the peak forecast is very similar in the near term (the delayed start of RTR does not impact the peak forecast as there is no decrease to the supply requirements associated with RTR peak demand) and slightly lower in the long term due to a revised EV peak impact. As a result, the system peak demand is expected to increase at an average of 1.1 percent annually over the forecast period, as shown in **Figure 2.**

Figure 2: Historical and Predicted Annual System Peak

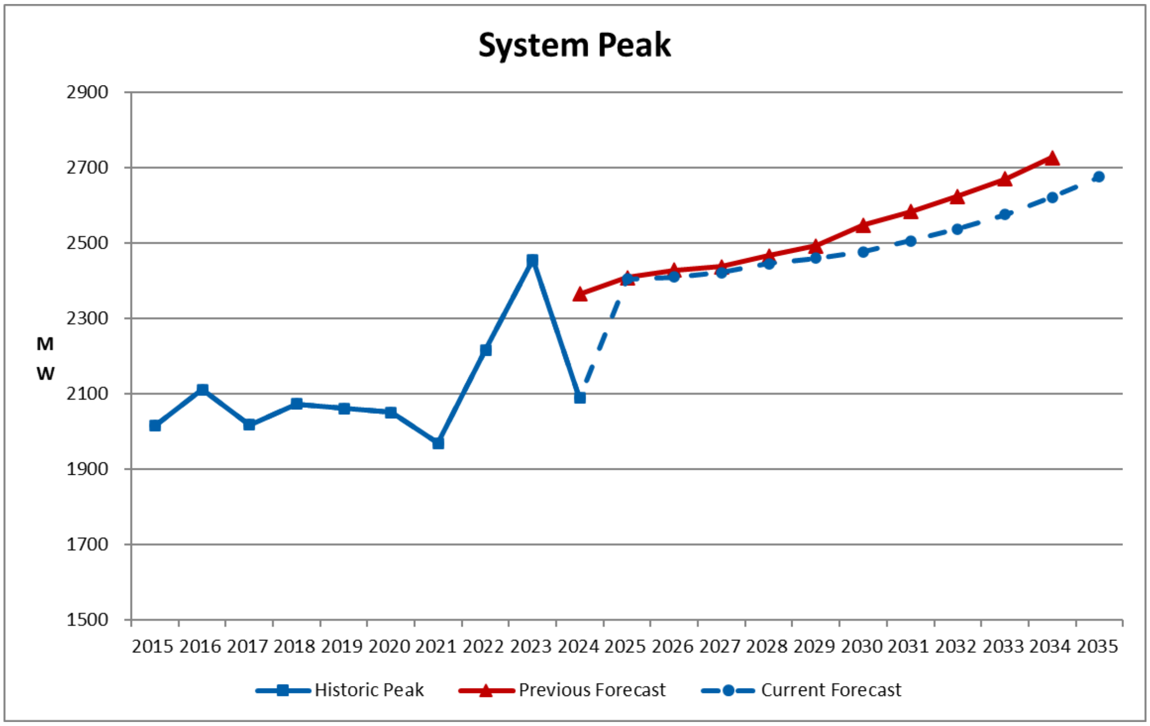


Figure 3 below shows the changes to system load and system peak over the historic and forecast periods.

Figure 3: Historic and Forecast Net System Requirement and System Peak

Year	NSR (GWh)	Growth (%)	System Peak (MW)	Growth (%)
2015	11,099	0.6	2,015	-4.9
2016	10,809	-2.6	2,111	4.8
2017	10,873	0.6	2,018	-4.4
2018	11,250	3.5	2,073	2.7
2019	11,077	-1.5	2,060	-0.6
2020	10,723	-3.2	2,050	-0.5
2021	10,902	1.7	1,968	-4.0
2022	11,134	2.1	2,216	12.6
2023	11,131	0.0	2,455	10.8
2024	11,326	1.8	2,088	-14.9
2025F	11,607	2.5	2,403	15.1
2026F	11,403	-1.8	2,408	0.2
2027F	11,193	-1.8	2,423	0.6
2028F	11,226	0.3	2,443	0.8
2029F	11,159	-0.6	2,458	0.6
2030F	11,130	-0.3	2,474	0.7
2031F	11,125	0.0	2,503	1.2
2032F	11,169	0.4	2,535	1.3
2033F	11,168	0.0	2,573	1.5
2034F	11,236	0.6	2,618	1.8
2035F	11,365	1.1	2,672	2.0

2.0 INTRODUCTION

NS Power develops an annual forecast of energy sales and peak demand requirements which assess the effects of end-use and economic factors on the future power system load and load shape. The forecast is a foundational input to the overall planning, budgeting and operating activities of the Company. Produced in the winter of 2024-2025 and using information available at the time, this forecast covers the period of 2025-2035. Unless otherwise noted, reported average annual growth rates are for the 2025-2035 period.

In 2024, the NSUARB initiated a paper hearing process to review the 2024 Load Forecast Report.[1] The Consumer Advocate (CA), the Small Business Advocate (SBA), the Industrial Group (IG), EfficiencyOne (E1), and Eastward Energy (EE) registered as intervenors. In addition, Board Counsel engaged Synapse Energy Economics (Synapse) to review and provide a report on NS Power's 2024 Load Forecast.

Following NS Power's response to Information Requests (IRs), filing of evidence by intervenors and Board Counsel and Reply Evidence by NS Power, the Board issued its Decision respecting NS Power's 2024 Load Forecast. The Board noted that "NS Power has agreed to many of the intervenors' recommendations and that this approach reflects the Utility's commitment to continuous improvement of the forecast."[2] The Board further stated as follows:

> As in previous Board decisions for the Load Forecast Reports, the Board encourages NS Power to pursue additional review with the aim of improving the forecast, specifically:
>
> - Evaluate the input variables in the residential model and test, over a period of time, if alternative inputs make the residential model more robust, considering the following:
>   - given the Provincial Government's population growth targets, changes to building permitting and funding such as the Housing

[1] NSUARB Hearing Order, 2024 Load Forecast Report (M11689), May 6, 2024.
[2] Nova Scotia Power Inc. 2024 Load Forecast Report, UARB Decision, October 22, 2024, page 8 (M11689).

Accelerator, re-evaluate the use of housing completions for the near-term;

- continue to provide a comparison of the short-term economic inputs provided by the Conference Board of Canada to ensure the data is close to what is used in the forecast of Canada's Big Five Banks;
- revisit the model's EV adoption rates to ensure the model's input aligns with the data reported by Statistics Canada and Nova Scotia Open data3; and
- continue to test the TVP elasticity in the load forecast as the elasticity changes over the course of the TVP Pilot.

While not identified as an issue in this proceeding, NS Power is directed to investigate if adjustments are needed in the 10-Year Forecast Classes to account for the Canadian Mortgage and Housing Corporation's (CMHC) housing completions data limitations. The CMHC housing completions data is restricted to population centres of 10,000+, whereas population centres below 10,000 are estimated on a sample basis in the last month of each quarter.

The Board directs NS Power to proceed with implementing the recommendations it has agreed to in the next Load Forecast report, including:

- to reassess the validity of the work from home variable;
- investigate trends in increasing maximum average temperature and cloud cover;
- update the Capacity Value Study for demand response before the next IRP analysis; and,
- continue to investigate the unexplained variance between forecast and actual NSR for the residential sector.

In accordance with the Board's direction, NS Power revised and enhanced the 2025 Load Forecast in the following manner:

- New residential customer forecast has been adjusted based on historic comparison of the Conference Board of Canada's forecast to actual. Please refer to **Section 4.3**.
- A comparison of economic indicators in the forecast versus forecasts from the major banks is provided in **Section 4.3**.

[3] Registration: Statistics Canada. Table 20-10-0025-01 New zero-emission vehicle registrations, quarterly and https://data.novascotia.ca/Permits-and-Licensing/Electric-Vehicle-Registration-Data/avxy-ifhs/data

- EV adoption rates have been adjusted to align with recent trends and the elimination of federal and provincial rebates. Please refer to **Section 4.4**.
- A comparison with the TVP elasticity is provided in **Section 4.5**.
- The work from home variable has been updated and is discussed in **Section 5.0** and **6.0**.
- Changing temperatures and cloud cover are discussed in **Section 4.2**.
- The Capacity Value Study update is discussed in **Section 10**.
- An analysis of the residential forecast variance for 2024 is provided in **Section 5.0**.

2.1 Summary of Stakeholder Consultations

On April 8, 2025, NS Power conducted a stakeholder session by videoconference with representatives of the NSUARB, the CA, the SBA, the IG, E1 and EE. The agenda and presentation materials are included in **Appendix E**. The NS Power Load Forecast team discussed the following changes to the 2025 Load Forecast:

- New residential load;
- New residential customer estimates;
- EV peak and energy update;
- Small scale solar (residential and commercial net metering);
- Renewable to retail impact;
- Class level trends;
- Variance of prior forecast to actuals; and
- Discussion of ongoing forecasting work.

3.0 FORECASTING APPROACH

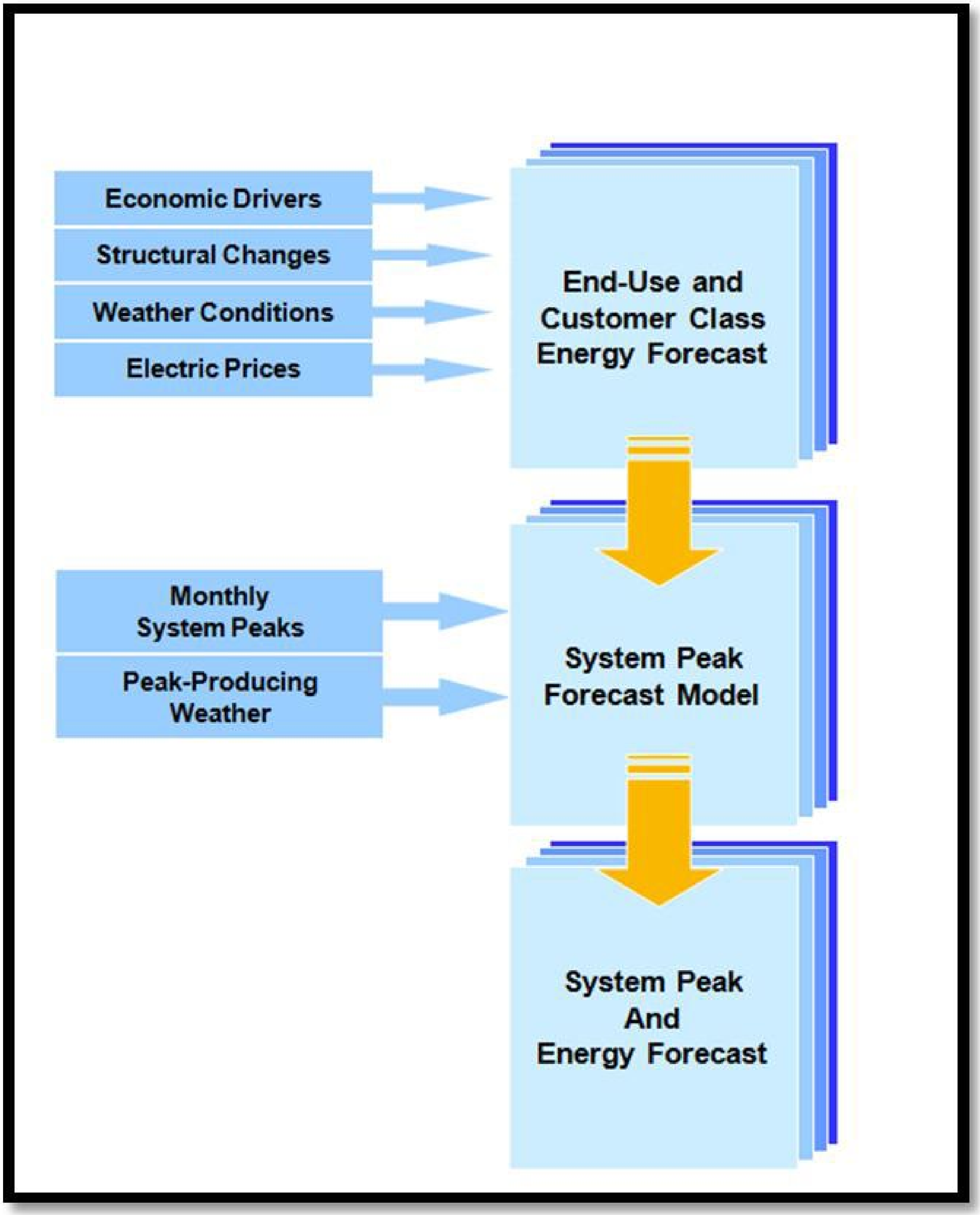
NS Power continues to use a set of SAE models for the Residential[4] and Commercial[5] rate classes, an econometric model for the Small and Medium Industrial classes, and customer surveys and historical data for the Large Industrial[6] customer classes.

The SAE model is a hybrid of the econometric and end-use methodologies, incorporating economic and end-use forecast variables into one model. An end-use model is a bottom-up approach that estimates the energy consumption of a customer group by summing the energy usage of all the appliances and equipment used by those customers. End-use forecasts are driven by trends in appliance usage and efficiency trends for that equipment. An econometric model describes the historical relationship between electricity consumption and independent economic indicators on provincial economic forecasts as a method to forecast future electricity sales.

The SAE model variables explicitly incorporate end-use saturation and efficiency projections, as well as changes in population, economic conditions, price, and weather. End-use efficiency projections include the expected impact of new standards and naturally occurring efficiency gains (efficiency improvements such as improvements in underlying technology that are not explicitly incentivized). In the long term, both economics and structural changes drive energy and demand growth. Structural changes are captured in the residential forecast model through the SAE model specifications. **Figure 4** shows the general forecast approach used in the SAE models.

[4] References to the Residential class include Domestic Service and Domestic Service Time-of-Day.
[5] References to the Commercial class include Small General, General and Large General unless specified otherwise.
[6] References to the Industrial class include the Small, Medium and Large Industrial classes unless specified otherwise.

Figure 4: Forecast Approach



4.0 DISCUSSION OF MAJOR INPUTS

4.1 Historical Class Sales and Energy Data

The Load Forecast is developed using NS Power's "billed" sales rather than "accrued" sales. Billed sales refer to the amount of energy billed to customers in a given period such as a calendar month or year. Accrued sales recognize the amount of energy generated and consumed during that specific time period. Due to the periodic nature and delays inherent in any meter reading and billing process, billed sales vary from accrued sales on a monthly basis but are essentially the same on an annual scale. Data from Advanced Metering Infrastructure (AMI) continues to be collected and analyzed, and will be used initially to improve estimates of accrued sales on a monthly basis. The forecast will transition to using AMI-based accrued sales once a sufficient historic data set is available.

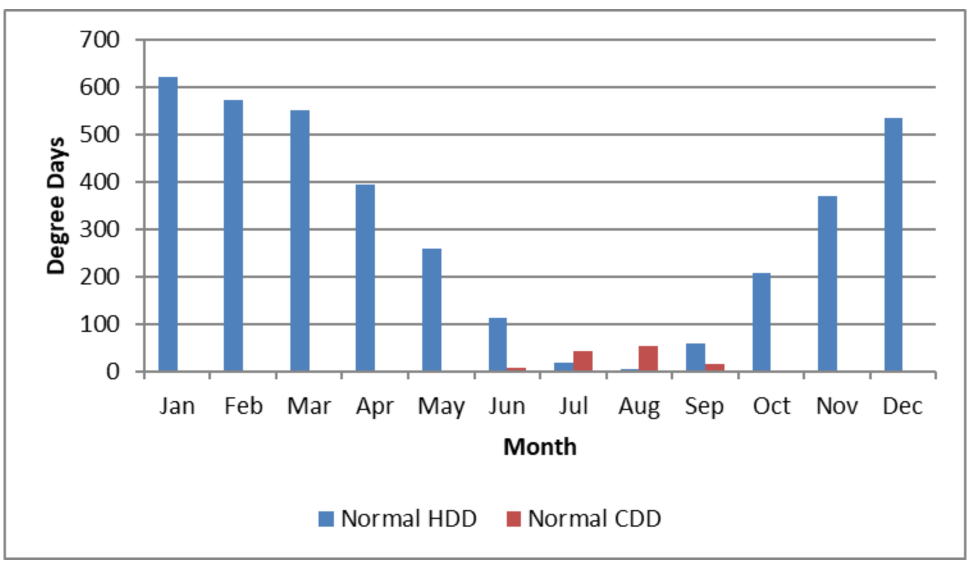
Historical monthly billed sales are the primary dependent variables in the linear regression models used in developing the forecast. For the 2025 Load Forecast, the residential and commercial energy forecasts are estimated using monthly billed sales data for the period January 2015 to December 2024. The industrial forecasts use the periods January 2015 to December 2024 (Small Industrial) and January 2006 to December 2024 (Medium Industrial) as these time periods improve the model fit.

For the peak demand forecast, historical system monthly energy and monthly demand data is derived from system hourly load data for the period January 2015 to December 2024. Large customer peak demand is forecast separately.

4.2 Weather Data

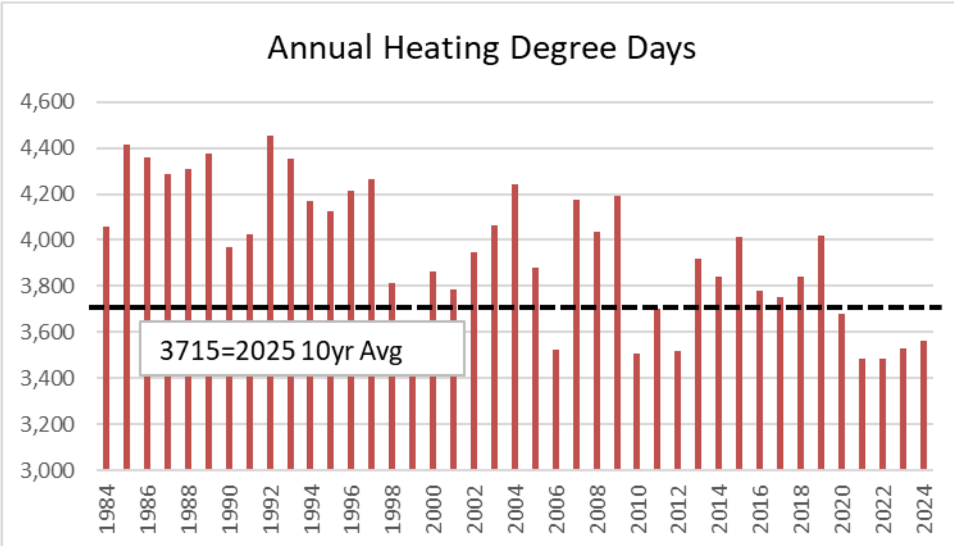
Weather conditions have the largest single impact on month-to-month variation in electric sales. The impact of temperature is captured by monthly Heating Degree Day (HDD) and Cooling Degree Day (CDD) variables. HDD are a common measure of heating requirement based on the degree difference between the daily mean temperature and a given reference temperature. The reference temperature of 18 degrees Celsius (°C) is used for these calculations. 18°C is assumed to be a comfortable room temperature below which space heating is generally required and above which space cooling is also required. Monthly HDD and CDD are calculated from Environment Canada hourly temperature information for the Shearwater Airport. Normal monthly HDD and CDD, as shown in **Figure 5** below, are calculated using 10 years of actual weather data covering the period January 2015 to December 2024. The average temperature continues to show a warming trend: the 30-year average annual HDD is 3,844 while the 10-year average is 3,715.

Figure 5: 10 Year Normal Monthly HDDs and CDDs



The annual number of HDD has been declining as a result of climate trends, as shown in **Figure 6**.

Figure 6: Historic Annual HDD



To reflect the general warming trend as seen in the 30-year vs 10-year averages, a trend is applied to the annual HDD and CDD variables. These trends are based on regression analysis of 30 years of historic data using a 10-year moving average (to smooth the series), with HDD decreasing by approximately 16 HDD/year, and CDD increasing by approximately 1.4 CDD/year. See **Figure 7** below for HDD and **Figure 8** below for CDD.

Figure 7: HDD Trend

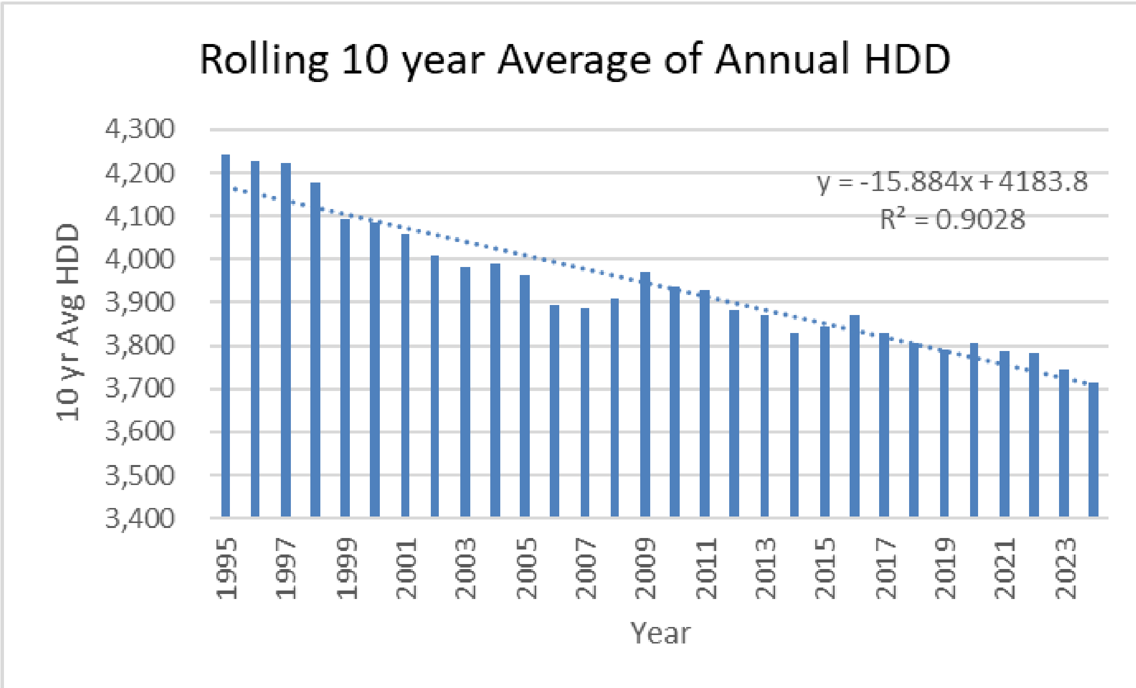
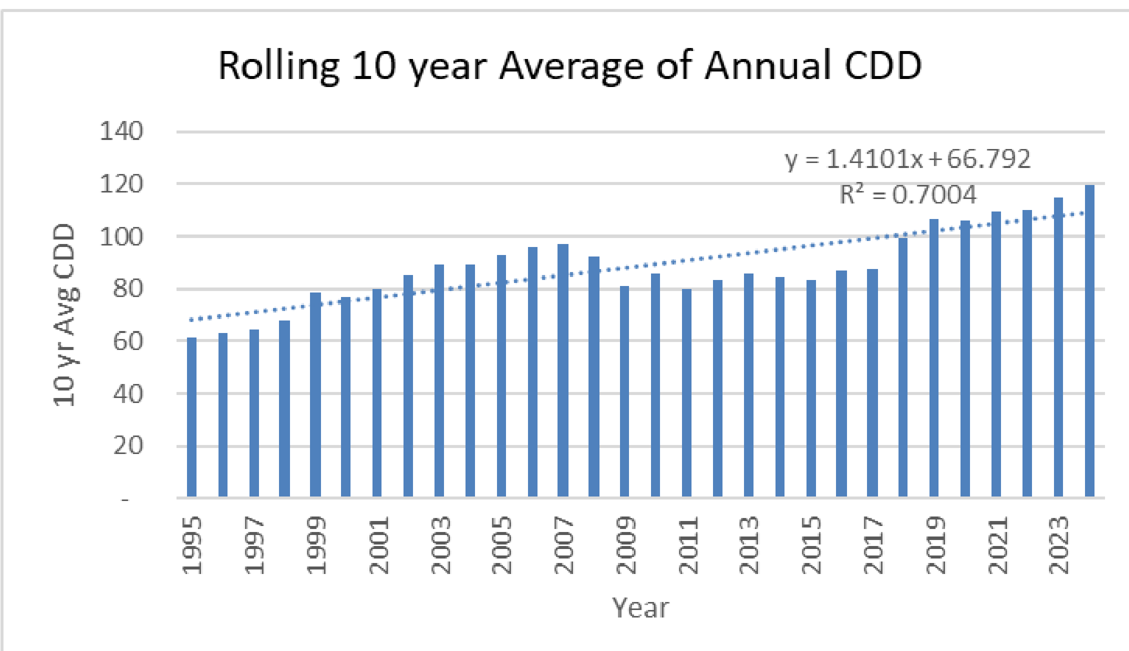
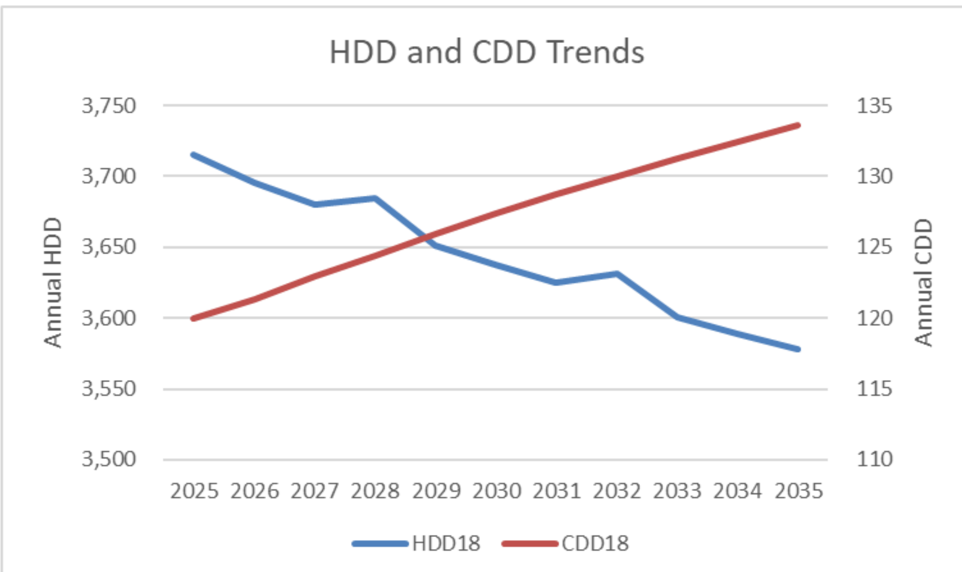


Figure 8: CDD Trend



These trends are reduced over time (approximately 40 years) such that the average annual HDD is not forced to 0 and the average annual CDD does not increase indefinitely. **Figure 9** shows how the HDD and CDD variables evolve over the 10-year forecast period. 2025 represents the 10-year average, and by 2035 the annual HDD value is reduced to 3,578 while the CDD value has increased to 134. The implication of this change is a reduced winter heating load and an increased summer cooling load in both the Residential and Commercial classes. The bumps in 2028 and 2032 are due to leap years which have an extra day in February.

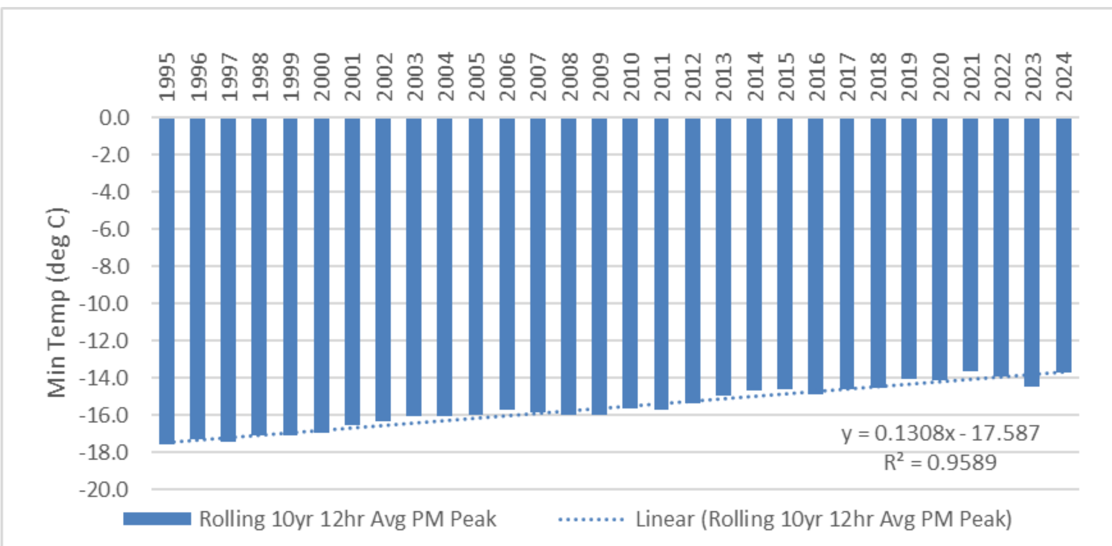
Figure 9: Annual HDD and CDD Over Time



Like the 2024 model, for the 2025 peak model the temperature input uses a 12-hour lagged temperature in combination with an average daily wind speed variable. In 2024 the 10-year averages for both parameters serve as the forecast variables, with an average 12 hour lagged temperature of -14.4°C and an average peak day wind speed of 17.5 km/h. Updating the 10-year temperature average with 2024 data would produce a peak temperature input of -13.6°C due to the introduction of a relatively warm peak day in 2024 and the removal of a relatively cold peak day in 2014. In order to minimize fluctuations in the peak temperature input this calculation has been updated for 2025 and is based on a rolling 10-year average of 10-year averages of the 12-hour lagged peak temperature, as found in **Figure 10**, which is -14.2°C. This will reduce year-to-year fluctuations in the peak temperature input, and will also better reflect the slowly warming peak conditions in Nova Scotia. The calculation of the input for windspeed remains unchanged, with a 10-year average value of 18.3 km/h. Fluctuations in this input variable has a much smaller impact on the peak model.

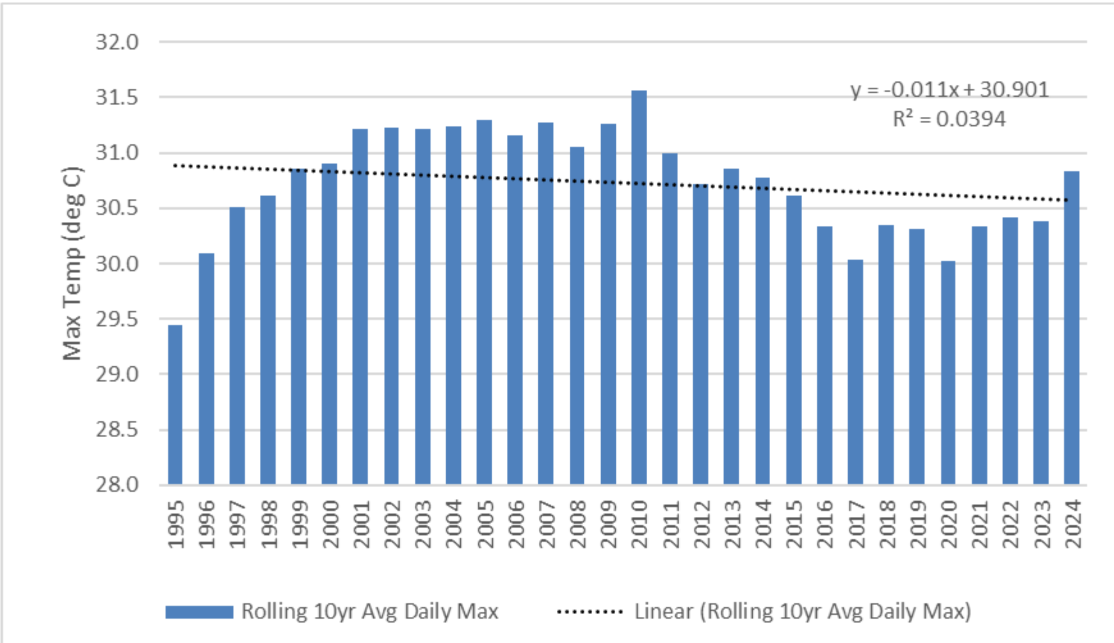
The other factor included in the peak forecast temperature is a trend similar to the one included in the annual HDD calculations. Looking at a rolling 10-year average of annual 12 hour lagged average minimum temperatures shows that the minimum is increasing at a rate of around 0.13 degrees per year, as shown in **Figure 10**. Like the trend in the HDD series, the peak trend also tapers off over a period of approximately 40 years.

Figure 10: Rolling 10 Year Average of Annual Evening Min Trend



Unlike winter peaks, the summer peaks (based on maximum annual temperature) do not show a clear trend, as shown in **Figure 11**. As a result, summer peak temperatures values are not adjusted in the forecast period, and rely on the 10 year average.

Figure 11: Rolling 10 Year Average of Annual Max Trend



The Climate Atlas of Canada[7] provides estimates for annual HDD as well as number of "Winter Days" that are -15°C or colder under different climate change scenarios between now and 2050. Annual HDD for Halifax is forecast to decline to a 30 year average of 3597 between 2021 and 2050 under the scenario where greenhouse gas emissions continue at present rates, or to 3636 where emissions slow. The number of "Winter Days" is forecast to decrease from a 30 year average of 13 (between 1976 and 2005) to around 6 under both scenarios. Both trends are in line with the trends being applied to annual HDD and peak temperature increases in the forecast. On the cooling side, annual CDD is expected to increase to 184 by 2050, with "Summer Days" increasing from 18 to 39 under the scenario where greenhouse gas emissions continue at present rates. This will increase overall cooling requirements but is unlikely to have a significant impact on summer peaks. The Climate Atlas of Canada predicts that the average warmest maximum temperature will only increase from 29.6°C to 31.5°C by 2050.

[7] https://climateatlas.ca/map/canada

4.2.1 Investigating the impact of cloud data on the Load Forecast

As requested by the Consumer Advocate, NS Power investigated the impact of cloud cover on energy and peak demand models. Since cloud cover data are not available from the Environment Canada weather station at Shearwater, which supplies other weather data used in the Load Forecast, an alternative dataset is used. The data are from the Modern-Era Retrospective Analysis for Research and Applications dataset, which is the latest atmospheric reanalysis produced by NASA's Global Modeling and Assimilation Office.[8] This dataset quantifies incident shortwave radiation at the surface ("SWin"), which is directly related to cloud cover via the processes of absorption and scattering. The data, specific to the Halifax area, is derived from satellite observations.

Metrics on the performance of energy and peak demand models – specifically, R^2 and Mean Absolute Percentage Error (MAPE) – were compared with and without the inclusion of the SWin dataset as an independent variable in the regression. **Figure 12** presents a comparison of the model performance under both conditions. The results indicate that inclusion does improve the forecast metrics, but the differences are minimal. Since no significant impact was observed, the SWin dataset was not incorporated into the final 2025 Load Forecast.

Figure 12: Model Performance with Solar Radiation

		Original	With SWin	Difference
Energy	R^2	0.978	0.981	0.003
	MAPE	2.57 %	2.42 %	-0.15 %
Peak	R^2	0.985	0.985	0.000
	MAPE	2.36 %	2.33 %	-0.03 %

[8] GES DISC Dataset: MERRA-2 tavg1_2d_lfo_Nx: 2d,1-Hourly,Time-Averaged,Single-Level,Assimilation,Land Surface Forcings V5.12.4 (M2T1NXLFO 5.12.4)

4.3 Economic Information

Economic and other provincial statistics used in the load forecast are from the Conference Board of Canada's 20-year forecast. This forecast provides a provincial perspective and considers specific Nova Scotia projects and demographics.

In the SAE framework, economic data drives the utilization of the end-use stock over the forecast period, with different indicators used in the different models. The impact of potential trade tariffs on these indicators is not included in the forecast, but the magnitude of the potential impact of economics on the long-term forecast is illustrated in **Figure 74**.

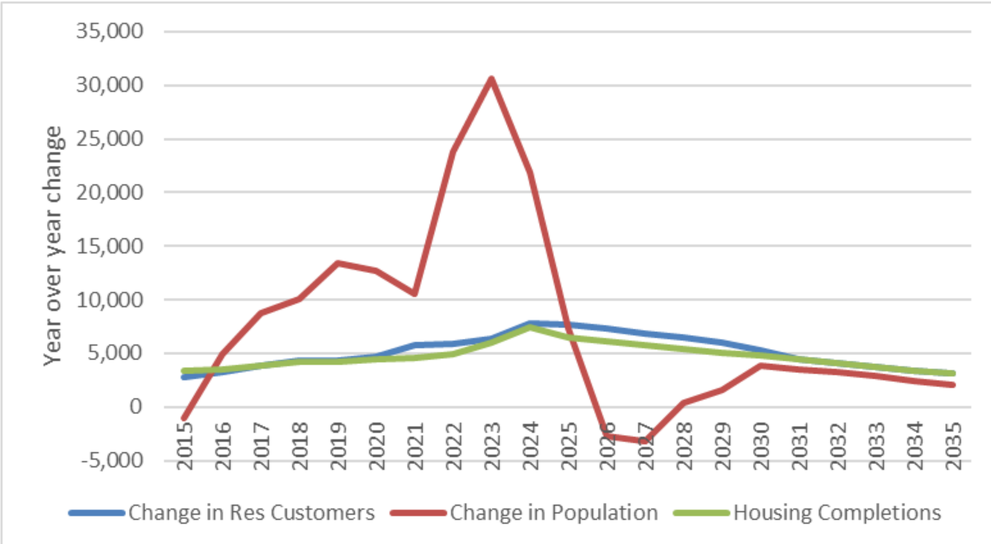
New housing completions for both single-family and multi-unit buildings as forecast by the Conference Board of Canada are used directly in the residential customer forecast. Growth of new customers is expected to remain positive but decrease over time, as population growth slows from the expected peak in 2024. As noted in its Decision, the NSUARB directed that:

> Given the Provincial Government's population growth targets, changes to building permitting and funding such as the Housing Accelerator, re-evaluate the use of housing completions for the near-term.[9]

Housing completion numbers continue to be highly correlated with residential customer count, as seen in **Figure 13**, and continue to be the most appropriate indicator in the near term. While population does impact housing development in the long term, it does not necessarily correlate with new customer additions in the near term.

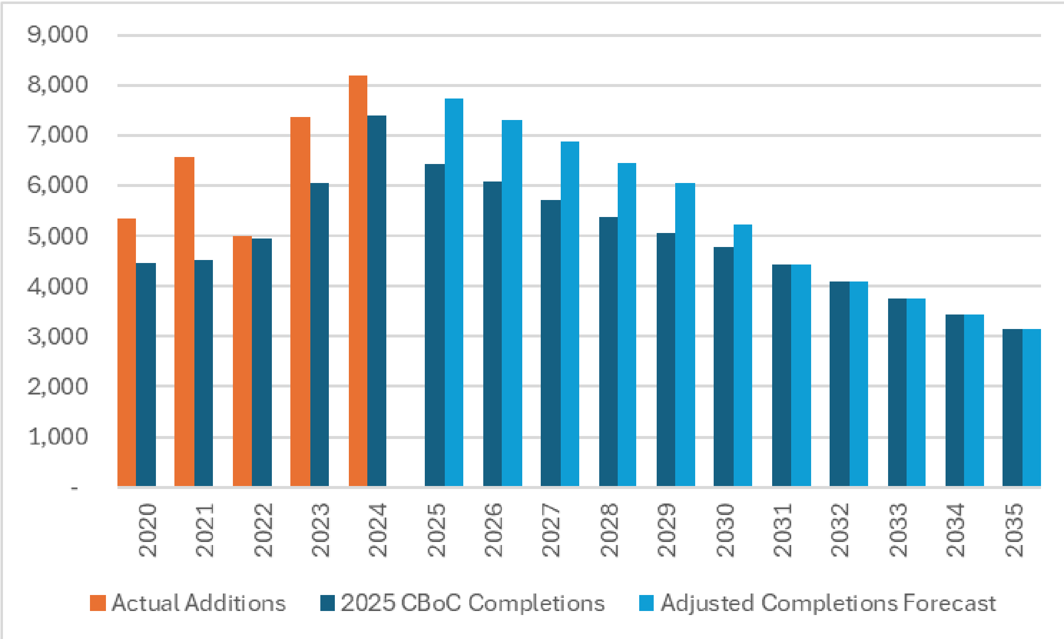
[9] Nova Scotia Power Inc. 2024 Load Forecast Report, UARB Decision, October 22, 2024, page 7 (M11689).

Figure 13: Yearly Change in Customers, Population, and Housing Completions



Comparing actual customer additions with the previous housing completion forecasts shows that the Conference Board of Canada indicator follows the same trend but underestimated actual customer additions by an average of 20 percent in the previous 5 years. This is also illustrated when comparing the Conference Board's forecast of housing starts to the forecasts from the major banks in **Figure 19**. The result is an adjustment of +20 percent to the Conference Board's forecast for housing completions in 2025 – 2030 to align with historic results, beyond 2031 the forecast for housing completions from the Conference Board is unadjusted, as seen in **Figure 14**.

Figure 14: Yearly Change in Residential Customers

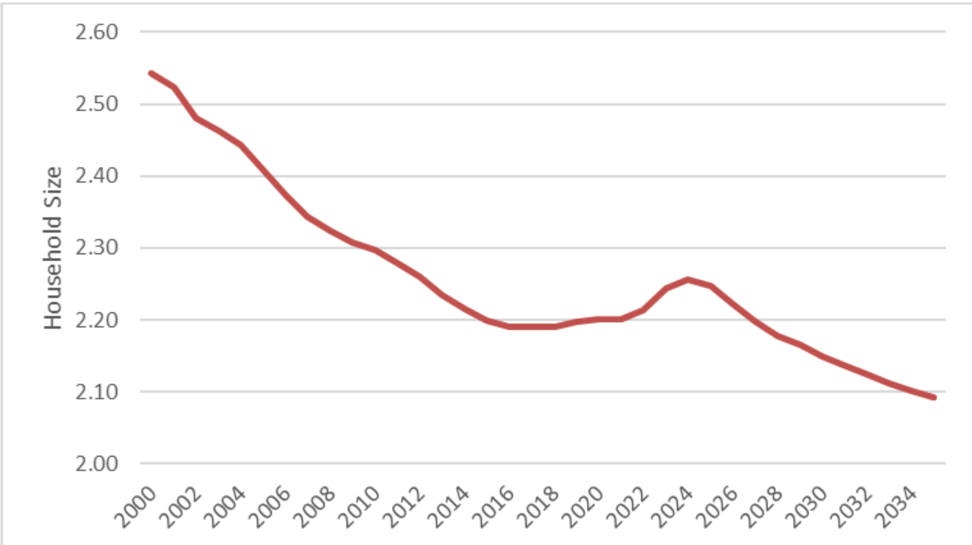


NS Power will continue to monitor any government initiatives that may increase housing supply. In a January 2025 update,[10] the Halifax Regional Municipality's summary of their Housing Accelerator Fund (HAF) targets indicates that the HAF initiatives are expected to increase housing development in HRM by 2,600 units over the next 3 years to 15,467 units (an increase of around 20 percent). These numbers are in line with the overall adjusted provincial completions used in the forecast, which total 21,895 over the next 3 years.

Regarding household size, population is currently used in combination with customer count to estimate average household size in the SAE model via the Heat Use, Cool Use, and Other Use variables (see **Appendix B**). As this number increases or decreases, the utilization rate of the corresponding usage variable will increase or decrease as well. **Figure 15** shows how the Household Size variable changes over time:

[10] HAF Action Plan Summary – Halifax Regional Municipality, NS, January 2025

Figure 15: Household Size



Household Size decreased steadily from 2000 to 2016 as population growth stagnated while new housing continued to increase. From 2016 to 2022 the average household size was steady around 2.2, but between 2022 and 2024 household size increases as population increases, with a decline after 2024 as population growth slows.

In the commercial models, non-manufacturing gross domestic product (GDP) and non-manufacturing employment continue to be used. In the industrial sector, rate classes are forecast using an econometric framework, with manufacturing GDP and manufacturing employment used as the economic drivers. The manufacturing employment forecast is based on the 2024 CBoC forecast as the 2025 CBoC forecast has a drop in both 2024 and 2025 (total decrease of over 2800 manufacturing jobs in the latest forecast) that is likely a result of Stats Can reporting and corresponding modeling rather than an actual drop in manufacturing employment. The regression timescale for the medium industrial model remains longer than the other class models (18 years vs 10 years for the residential model) to help improve the relevance of the economic variable in the small industrial model (the model produces a high P-value on the economic variable using a 10-year timeframe) and to help improve the fit in the medium industrial model (adjusted R- squared of 0.329 for 10 years vs 0.688 for 18 years**). Figures 16, 17** and **18** summarize the economic drivers, on an annual basis, used in the 2025 Load Forecast. For financial measures, the variables have been adjusted to constant dollars, eliminating the inflation effects from the series.

Figure 16: Residential Economic Drivers

Year	New Construction (number)	% Change	Household Compensation (mil $2002)	% Change
2015	3,333		17,488	
2016	3,468	4.1	17,118	-2.1
2017	3,858	11.2	17,517	2.3
2018	4,214	9.2	18,036	3.0
2019	4,208	-0.2	18,061	0.1
2020	4,470	6.2	18,077	0.1
2021	4,509	0.9	18,915	4.6
2022	4,949	9.8	19,198	1.5
2023	6,057	22.4	20,077	4.6
2024	7,399	22.2	21,117	5.2
2025	7,726	4.4	21,166	0.2
2026	7,302	-5.5	21,143	-0.1
2027	6,867	-6.0	21,150	0.0
2028	6,459	-5.9	21,223	0.3
2029	6,054	-6.3	21,296	0.3
2030	5,237	-13.5	21,409	0.5
2031	4,432	-15.4	21,521	0.5
2032	4,089	-7.7	21,660	0.6
2033	3,753	-8.2	21,813	0.7
2034	3,431	-8.6	21,979	0.8
2035	3,150	-8.2	22,136	0.7
15-24		9.3		2.1
25-35		-8.6		0.4

Figure 17: Commercial Economic Drivers

Year	Non-Manufacturing GDP (mil $2017)	% Change	Non-Manufacturing Employment (000)	% Change
2015	35,285		415	
2016	35,780	1.4	413	-0.4
2017	36,535	2.1	415	0.4
2018	37,126	1.6	419	1.0
2019	38,312	3.2	430	2.8
2020	36,607	-4.4	414	-3.9
2021	38,850	6.1	442	6.8
2022	40,287	3.7	457	3.5
2023	41,163	2.2	470	2.9
2024	42,028	2.1	486	3.3
2025	42,536	1.2	491	1.0
2026	43,130	1.4	490	-0.1
2027	43,750	1.4	490	-0.1
2028	44,358	1.4	490	0.1
2029	44,945	1.3	491	0.1
2030	45,586	1.4	491	0.1
2031	46,186	1.3	492	0.1
2032	46,800	1.3	493	0.2
2033	47,416	1.3	494	0.2
2034	48,032	1.3	496	0.3
2035	48,647	1.3	497	0.2
15-24		2.0		1.8
25-35		1.4		0.1

Figure 18: Industrial Economic Drivers

Year	Manufacturing GDP (mil $2017)	% Change	Manufacturing Employment (000)	% Change
2015	2,740		29	
2016	2,762	0.8	29	1.2
2017	2,794	1.2	30	5.1
2018	2,896	3.6	33	7.6
2019	3,093	6.8	34	2.3
2020	2,918	-5.6	33	-0.6
2021	3,251	11.4	34	1.8
2022	3,268	0.5	35	4.1
2023	3,290	0.7	35	-0.1
2024	3,246	-1.4	36	0.8
2025	3,331	2.6	36	0.3
2026	3,415	2.5	36	0.3
2027	3,525	3.2	36	0.5
2028	3,652	3.6	36	0.5
2029	3,790	3.8	36	0.7
2030	3,935	3.8	37	0.6
2031	4,058	3.1	37	0.7
2032	4,183	3.1	37	0.8
2033	4,308	3.0	38	0.9
2034	4,435	3.0	38	0.9
2035	4,563	2.9	38	0.9
15-24		1.9		2.4
25-35		3.2		0.7

The major Canadian banks provide short term (1-2 year) forecast for some of the key economic indicators, and these are provided in **Figure 19**. The Conference Board of Canada forecast is in line with the forecasts from the banks with the exception of housing starts. The adjustment to housing completions discussed above brings the forecasted housing completions in line with the forecasted housing starts from the banks.

Figure 19: Economic Forecast Comparison

	GDP		Employment		Housing Starts	
	2025 (%)	2026 (%)	2025 (%)	2026 (%)	2025	2026
Conference Board of Canada	1.3	1.5	0.9	0.0	4851	4453
BMO[11]	1.7	1.3	0.8	1.0	12000	10000
RBC[12]	1.5	1.3	2.8	2.4	7000	7000
TD[13]	1.4	1.3	0.1	-0.1	6400	6300
Scotiabank[14]	1.8	1.5	1.6	1.4	6700	6300

4.4 End-Use Trends

In addition to economic data, the SAE model also uses end-use data, in the form of saturations and efficiencies, from NRCan and the US Energy Information Agency (EIA). NRCan data for the residential sector is specific to Nova Scotia, while NRCan data for the commercial sector is for Atlantic Canada. EIA data is for New England and is calibrated to fit existing Nova Scotia data.

The approach to developing the individual end-use intensities is to start with historical NRCan end-use saturation trends combined with data derived from surveys and use year-over-year changes in saturation projections and end-use efficiency estimates for the New England Census Division. The resulting end-use intensity trend is then compared with end-use energy estimates from NRCan. If necessary, it is then adjusted so that the resulting intensities are consistent with NRCan reported end-use consumption and actual average use derived from NS Power billing data.

In the case of end uses where there is little historical activity or where future behaviour is expected to vary significantly from the existing data set due to targeted programs, these are modeled outside the average use intensities. EVs and rooftop solar photovoltaic (PV) continue to be modeled outside the average use intensities as they have little historic data. This method also allows these

[11] BMO Provincial Economic Outlook, Dec 2024
[12] RBC Provincial Forecast, Dec 2024
[13] TD Provincial Economic Forecast Dec 2024
[14] Scotiabank Global Economics, Provincial Outlook, Dec 2024

items to be tracked more directly to help fine-tune future forecasts. The PV forecast has been updated based on actual installations in 2024. Key end uses are discussed individually below.

As with the 2024 Load Forecast, the forecasts developed by third party consultant E3 for space heating and EV load shapes are used. The space heating forecast uses the uptake required to meet stated emission goals over the next 20 years, without assuming any specific changes to regulations or incentives, though both are possible in the timeframe of the current 10-year load forecast.

4.4.1 Heat Pumps

Heat pump usage continues to grow in the province as more customers find heat pumps an efficient way to heat and cool buildings as well as providing environmental and financial benefits. The end-use model uses an estimated saturation of 48 percent of customers supplying their heat via heat pumps in 2025. The estimated number of customers who installed heat pumps in 2024 was almost 22,250, around 1,000 more installs than estimated in the 2024 forecast. This level of uptake is expected to continue in the near term given the continued availability of grants and financing ($300/ton for qualifying mini splits, $500/ton for qualifying ducted systems and up to $15,000 for oil conversions for low and median income households). The result is continued strong uptake that is expected to continue through the forecast period. As with the 2024 forecast, the E3 scenario used in the forecast is the hybrid scenario, where a portion of customers adopting heat pumps retain their non-electric backup heating systems to provide heating on the coldest days. This assumption is in line with the Nova Scotia Power Electrification Strategy Report released in late 2023, which states "Winter peak impacts on the electricity system from cold-climate heat pumps can be mitigated by encouraging hybrid (mini-split) systems and best-in-class performing heat pumps."[15] As stated in response to E1 IR-02 in the 2024 Annual Capital Expenditure proceeding, "The province's 2030 Clean Power Plan calls for peak management, demand response and efficiency investments to reduce 150 MW of peak and peak growth by 2030. The Hybrid Peak Mitigation electrification scenario, with its modeled peak reduction of 100 MW beyond those achieved via

[15] The Economics of Electrification in Nova Scotia, Energy+Environmental Economics, Oct 2023, page 7

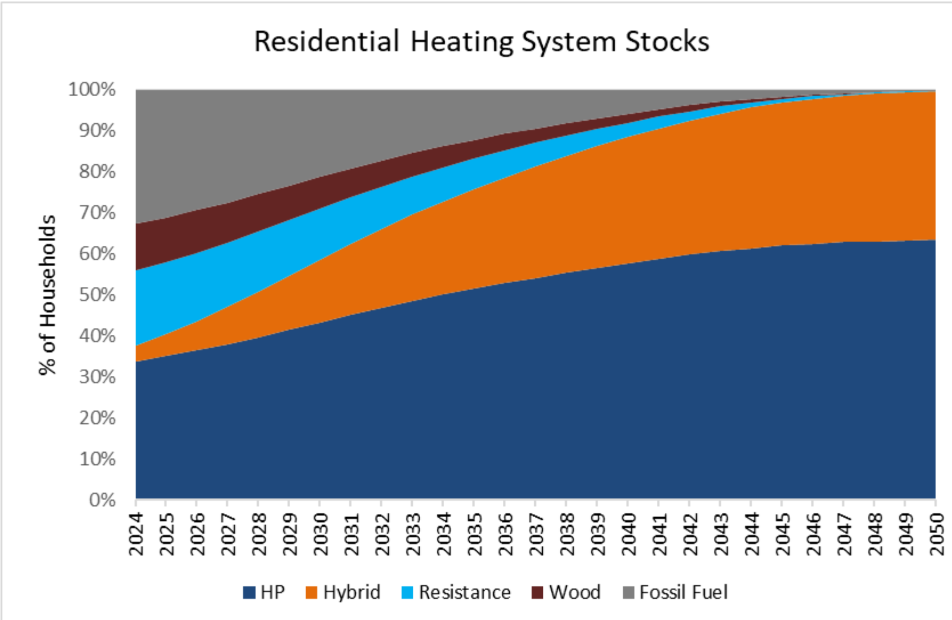
the demand response and efficiency programming incorporated in the Base DSM scenario, is the scenario studied in the Evergreen IRP which most closely matches this objective."[16] The forecast continues to assume 100 percent heat pump saturation in the residential sector in order to achieve carbon reduction targets of net-zero by 2050 as shown in **Figure 20.** The Province's work to study the hybrid scenario was described in the Company's update to The Path to 2030 provided in the 2025 ACE Plan, and stated as follows:

> To fully assess the value of the hybrid peak scenario, NS Power is committed to participating in study work to determine the corresponding cost impacts of potential customer programs (please refer to the Action Plan Item 4b). This study, with engagement and participation from multiple organizations including NS Power, will provide a balanced assessment of the cost impacts of the hybrid approach and provide the necessary information to conduct a more refined assessment of the program from an electricity system cost perspective.
>
> In the first half of 2024, NS Power met with NRR on their approach to a Hybrid Peak study as part of the Load Management initiative of the Clean Power Plan. Net Zero Atlantic initiated a study to examine Hybrid Peak options in the fall of 2024 on behalf of NRR. The study will include key stakeholders within the province including E1 and organizations representing fossil fuel heating sources used in Nova Scotia. NS Power has agreed to complete resource planning modeling in support of the study objectives. NS Power understands that the current estimated timeline for completion of the study is Q3 2025.[17]

To date, NS Power has participated in meetings with Net Zero Atlantic and provincial staff in a working group setting. Net Zero Atlantic is acting as the lead party completing the study. This work will continue into 2025.

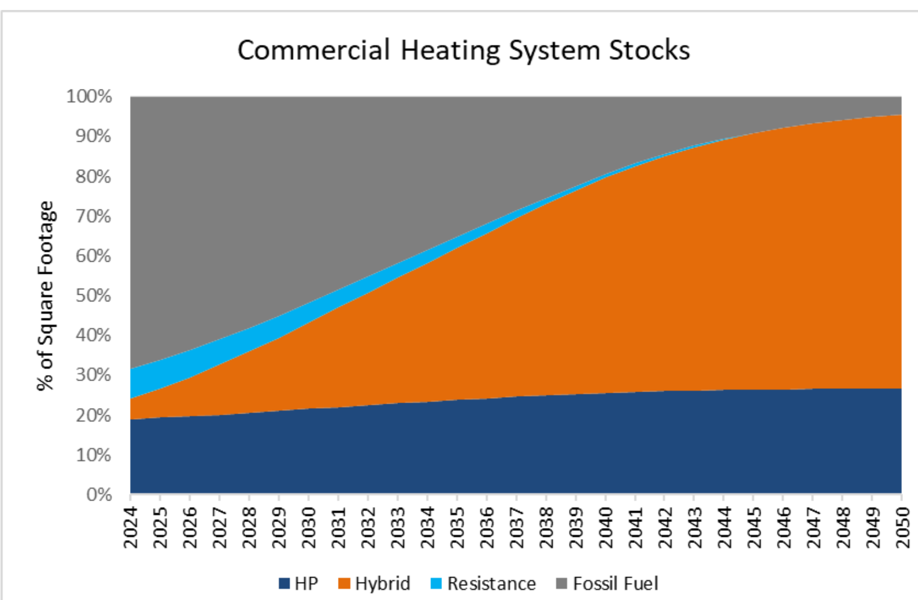
[16] 2024 ACE Plan (M11458), EfficiencyOne IR-02 part (b), February 9, 2024, page 3.
[17] 2025 ACE Plan Appendix H, The Path to 2030, M12012, December 9, 2024, pages 40-41.

Figure 20: E3 Residential Space Heating Saturation



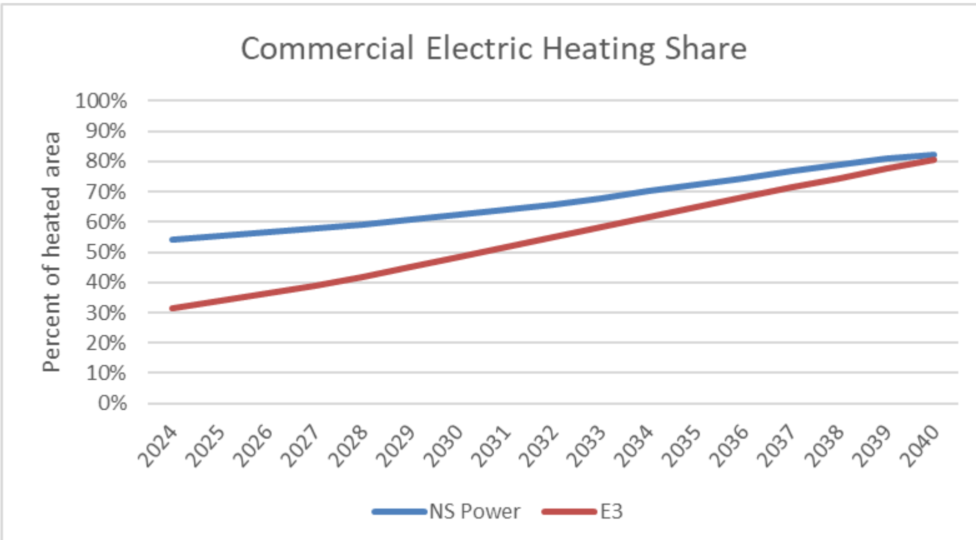
On the commercial side, the E3 electric heating stock model has a similar trajectory to that of the residential model (see **Figure 21**), but has a higher adoption of hybrid systems and does not reach 100 percent by 2050 as there will be a portion of the buildings that may not be able to fully convert.

Figure 21: E3 Commercial Space Heating Saturation



E3 saturation estimates had a lower starting point than the NS Power models, so the NS Power series was adjusted to meet the E3 series by around 2040 as shown in **Figure 22**, resulting in a slightly lower trajectory.

Figure 22: Commercial Space Heating Saturation Comparison



For the 2024 forecast, energy and peak values predicted by the SAE models are higher than the E3 hybrid scenario models where some of the heating requirements are handled by the secondary non-electric heat source. **Figure 23** shows the estimated energy and peak impact from the NS Power models compared to the E3 projections, as well as the corresponding adjustments to the energy and peak forecast values. These adjustments are applied to the model to estimate the impact of the hybrid scenario.

Figure 23: Heat Pump Energy and Peak Comparison

Year	NS Power HP Energy (GWh)	E3 HP Energy (GWh)	Change in Energy Forecast (GWh)	NS Power HP Peak (MW)	E3 HP Peak (MW)	Change in Peak Forecast (MW)
2030	235	74	-161	97	83	-14
2035	494	205	-289	207	176	-31

E3 commercial values adjusted to account for share difference

Figure 24 shows the forecast for residential installations and changes to saturation and intensity over the forecast period.

Figure 24: Heat Pump Forecast

Year	Total Cumulative New Installs	% Install Non-Elec. Heat	% Install Elec. Heat	Overall % Sat. for Heating	Overall Heating Intensity (kWh/house)	Overall % Sat. for Cooling	Overall Cooling Intensity (kWh/house)
2025	22,636	66	34	48	2,289	59	234
2026	45,033	66	34	51	2,477	64	248
2027	67,138	66	34	55	2,665	68	262
2028	88,893	66	34	58	2,853	72	276
2029	110,235	66	34	62	3,022	75	288
2030	131,097	66	34	65	3,188	79	301
2031	151,408	66	34	68	3,351	83	313
2032	171,093	66	34	72	3,514	86	325
2033	190,074	66	34	75	3,667	90	336
2034	208,272	66	34	78	3,816	93	347
2035	225,606	66	34	80	3,945	96	358

The overall heating intensity is similar to the 2024 forecast, with higher intensity by 2035 as a result of a higher number of installs.

4.4.2 Water Heaters

NS Power anticipates that some customers who convert their oil heating systems to heat pumps will also convert their hot water supply to electric hot water tanks because of the annual operating savings. Growth is expected to remain steady, with saturation increasing to 90 percent by 2035. As part of a joint demand response working group, NS Power and E1 are continuing with a program that involves controlling water heaters directly to achieve benefits to the system (see **Section 10)**. **Figure 25** shows the expected changes in saturation and overall intensity over the forecast period. The efficiency improvements of heat pump hot water heaters are still not incorporated into the forecast directly as uptake is still small (163 in 2022 and 141 in 2023 according the 2023 DSM Programs Evaluation Report filed by EfficiencyOne[18]) despite an available rebate of $400. However, overall efficiency is expected to improve over the forecast period through a combination of new heat pump technology as well as replacement of existing stock with improved efficiency units.

Figure 25: Water Heater Forecast

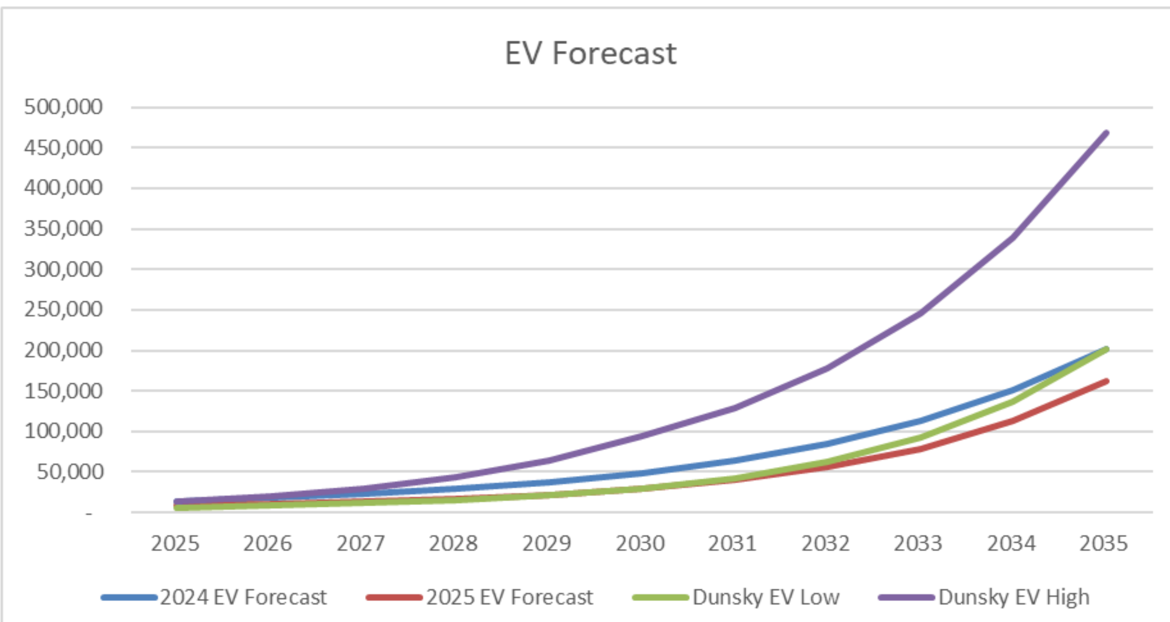
Year	Overall % Saturation	Overall Intensity (kWh/household)
2025	76	1,674
2026	78	1,709
2027	80	1,743
2028	82	1,777
2029	83	1,808
2030	85	1,825
2031	86	1,843
2032	87	1,861
2033	88	1,879
2034	89	1,897
2035	90	1,916

[18] 2023 DSM Programs Evaluation Reports, Residential Efficient Product Rebates Program, EfficiencyOne, Table 17, page 20.

4.4.3 Electric Vehicles (EVs)

Both the federal and provincial incentives on EV sales have been eliminated for 2025, with the exception of medium and heavy-duty vehicles. This will have a negative impact on EV sales in the province, and the forecast has been adjusted accordingly. It is estimated that there were approximately 6,500 BEV + PHEVs (together considered as EVs) in the province as of the end of 2024. The predicted slow down in EV sales will result in a lower forecast than both 2024 and the "Low" scenario in the report entitled "Ensuring ZEV Adoption in Nova Scotia."[19] A comparison of the 2025, 2024, Dunsky Low and Dunsky High scenarios is shown the **Figure 26**.

Figure 26: EV Forecast



The forecast includes both light-duty vehicles (LDV) as well as medium-duty vehicles (MDV) such as delivery trucks and other medium-duty fleet vehicles, and heavy-duty vehicles (HDV) focusing on buses. The revised EV forecast estimates that Nova Scotia will have over 160,000

[19] https://ecologyaction.ca/sites/default/files/2023-05/RegionalZEVAdoptionOptions_Dunsky_March2023.pdf, prepared by Dunksy Energy+Climate Advisors for the Ecology Action Center

EVs on the road by 2035, mostly made up of LDVs compared to a forecast of 200,000 vehicles by 2035 in the 2024 Load Forecast.

The impact of EVs on residential energy sales and peak (reflecting at-home charging) was analysed using AMI data from 2023 and 2024. Customers were selected based on the detection of EV charging signatures in their data, and only on the standard residential rate. This detection was performed by a contracted analytics vendor. Customers were divided into two groups:

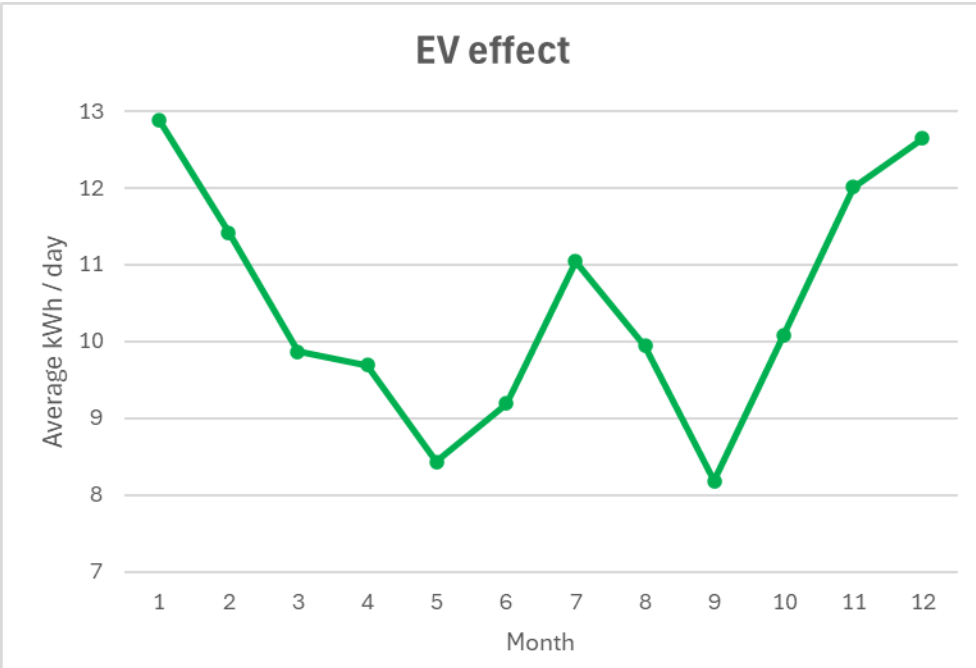
- "New EV owners": These customers were first detected as having an EV at some point during the 2-year study period.

- "Control group": These customers were detected as having an EV throughout the whole study period.

For estimating overall energy impact of EVs, consumption data for customers in each group was compared month-by-month for consecutive years. For example, data for January 2023 (Y1) was compared to data for January 2024 (Y2), for each group. In this case, customers in the new EV owners' group were not detected as having an EV in January 2023 but they were in January 2024, whereas customers in the control group were detected as having an EV in both years. The difference Y2 – Y1 for customers in the new EV owners' group is assumed to be a result of the addition of EV charging to the household load plus any impact from natural variability (e.g., varying weather conditions between the two years). The difference Y2 – Y1 for customers in the control group is assumed to only be a result of natural variability. Therefore, the impact of EV charging alone (herein "EV effect") is estimated as the difference between years for the sample group less the difference between years for the control group. Using this same method, coincident peak EV effect was taken as the maximum Y2 – Y1 kW difference for hour-ending 8 pm.

Aggregated across a whole year, the EV effect represents a load increase of 3820 kwh per year, per customer from at-home charging (not including public charging). On a monthly basis, the greatest load impact is in the winter, with a secondary peak in the summer (**Figure 27**). The coincident peak impact is determined to be 0.39 kW for at home charging (again, not including public charging of LDVs). An example of time-of-day variation in EV effect is given in **Figure 73**.

Figure 27: Average Daily Impact of EV



These results are used to forecast residential customers charging at home, but the impact of commercial charging and medium and heavy duty vehicle charging continues to come from the estimates provided by E3's EV Load Shaping Tool. E3's tool simulates driving and charging of electric vehicles in Nova Scotia, based on a bottom-up modelling approach and produces a load shape that captures the diversity of driving behavior, EV types, and charging access across the Nova Scotia driving population. **Figure 28** shows the EV load and peak demand contribution estimated from the load shapes provided by E3, including the impact to LDV load and peak from both at-home and public charging (assumed to add 10 percent to annual energy and 0.2 kW/vehicle to peak based on the E3 load shapes).

Figure 28: EV Mileage Assumptions and Load/Peak Modeling Results

Vehicle Type	Avg kWh/year	Avg kW/vehicle on Peak
LDV	4,202	0.6
MDV	8,205	1.6
HDV	113,890	7.3

Figure 29 provides the estimated energy and peak impacts that correspond to the number of EVs in the forecast, along with a sensitivity showing potential peak impact based on the maximum non-coincident residential peak calculated in the analysis, which was 0.5 kW/vehicle and occurred at hour ending 2400 in December, combined with the unmanaged scenarios from E3. The peak loads shown are overall averages including LDV, MDV and HDV impacts to peak.

Figure 29: EV Impact to Energy and Peak Forecasts (cumulative)

Year	New EVs	New Load (GWh)	Peak @ 0.7kW/ vehicle (MW)	Peak @ 1.2kW/ vehicle (MW)	Total EVs	Total Load (GWh)	Peak @0.7kW/ vehicle (MW)	Peak @1.2kW/ vehicle (MW)
2025	1,832	10	1	2	8,332	32	5	7
2026	4,274	29	4	6	10,774	51	8	11
2027	7,283	49	6	11	13,783	70	10	16
2028	11,325	75	9	17	17,825	97	13	22
2029	16,860	108	14	24	23,360	129	18	29
2030	24,612	148	19	33	31,112	170	23	38
2031	35,673	200	27	45	42,173	221	31	50
2032	51,657	270	38	60	58,157	292	41	65
2033	74,964	368	53	81	81,464	390	56	86
2034	109,183	511	74	110	115,683	532	78	115
2035	159,663	718	106	152	166,163	740	109	157

4.4.4 Solar Generation (PV)

Solar generation consists of two main types – distributed small-scale solar (mainly rooftop) that falls under NS Power's net metering program, and small- to large-scale generation that is fed directly onto the grid via power purchase agreements or direct utility ownership.[20] In the Load Forecast, only the former is considered, as it serves as a reduction in load in the residential and commercial classes. The 2024 Load Forecast was for 3,019 new installations, while the actual number was 2,853, for a cumulative total of 11,082 (101 MW) by the end of the year.[21] As of 2024, the average installed capacity is approximately 8.5 kW for residential customers and 26 kW for non-residential, and total annual net metering solar generation is estimated at 110 GWh. The average capacity factor is estimated to be 12.5 percent, and average production is 9,600 kWh/customer.

The number of solar installations is expected to increase in the coming years as a result of continued initiatives such as Property Assessed Clean Energy Programs (e.g. Solar City in Halifax), Canada Greener Homes interest-free financing, and commercial incentives that include investment tax credits and accelerated capital cost allowance. The forecast continues to reflect these trends, with total installed capacity of 930 MW by 2035. This assumes that incentives continue to be available in the coming years. The overall impact is shown in **Figure 30**. There is no forecast reduction in NS Power peak demand, as solar generation occurs at times non-coincident with NS Power's system peak (refer to **Section 10** for further discussion on peak impacts).

[20] The Smart Grid Nova Scotia solar garden in Amherst falls under direct utility ownership.
[21] NS Power, 2024 Net Metering Report, March 27, 2025.

Figure 30: PV Impact to Energy (cumulative)

Year	New Installs	Load (GWh)	Peak (MW)	Total Solar Installs	Total Load (GWh)
2025	3,085	-38	0	14,167	-148
2026	6,615	-82	0	17,697	-192
2027	10,676	-133	0	21,758	-243
2028	15,351	-191	0	26,433	-301
2029	20,724	-258	0	31,806	-368
2030	26,905	-335	0	37,987	-445
2031	34,013	-433	0	45,095	-542
2032	42,182	-536	0	53,264	-646
2033	51,579	-656	0	62,661	-766
2034	61,442	-781	0	72,524	-891
2035	71,798	-913	0	82,880	-1023

Although solar generation reduces customer consumption overall, much of their consumption is still provided by the utility. Around 50 to 60 percent of customers production is exported to the grid (mostly in summer months) and serves as a credit against consumption at other times of the year. Analysis of AMI data also shows that on average, net metering customers have higher peak demands than non-net metering customers in both summer and winter periods as show in **Figures 31** and **32** below.

Figure 31: Average Winter Profiles

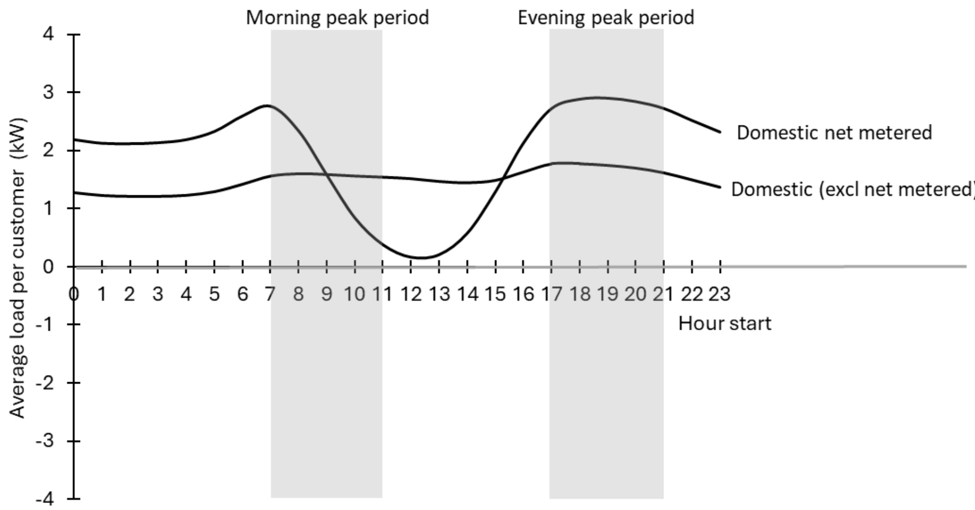
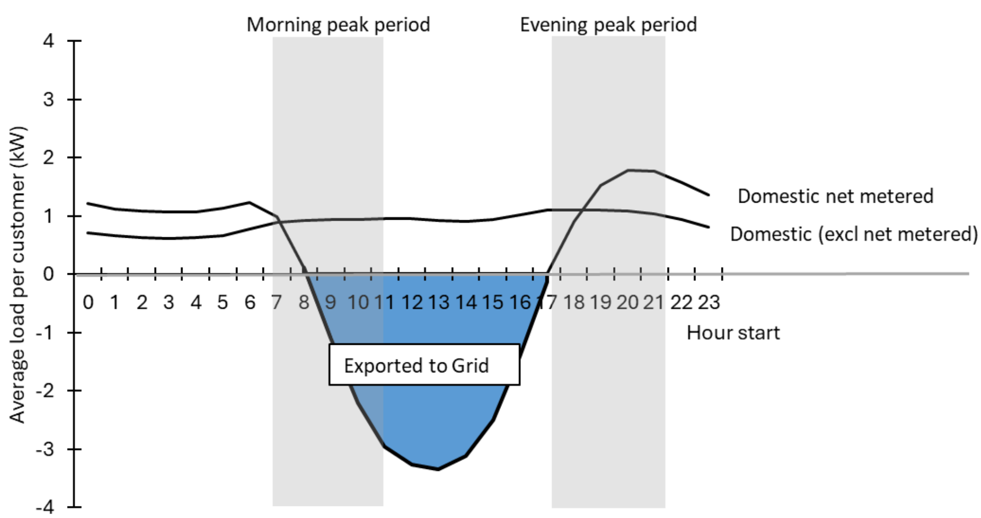


Figure 32: Average Summer Profiles



4.4.5 New Technologies

The 2025 Load Forecast does not assume a significant amount of distributed solar/battery storage combinations or storage only deployments. The cost of home batteries is still relatively expensive, in the range of $15,000-$20,000[22] for a single battery and installation (for 5-7 kW batteries). This is more expensive than the cost of a gas-powered generator, which varies from as little as $1,000 for a moderately sized stand-alone generator to supply plug loads (also around 5-7 kW), up to $10,000 or more for an installed whole-home generator. Currently, the only major driver for residential batteries is for back-up power, so gas generators are a more cost-effective solution. The Time Variable Pricing (TVP) rates currently being piloted might start to encourage battery installation either alone or in conjunction with solar panels, but the initial costs associated with batteries are still high. As battery technology improves and costs come down over time, this is likely to change, but research in these areas is ongoing and timelines for significant shifts in this technology are unknown.

Vehicle-to-Grid (V2G) is a technology that would allow electric vehicles to supply energy to a home, supply energy to the grid, or vary their charging behaviour in response to signals from the grid. The technology is still in development, as are the associated codes and standards, and it is not widely available at the moment. A few manufacturers have included some capability in existing vehicles (the Nissan Leaf and Ford F150 are examples) or have announced that they will provide elements of V2G capability in the near future.

Energy limited devices like batteries and vehicle-to-grid can also discharge to support the system, further capitalizing on the coordinated opportunity of distributed energy resources. For example, **Figure 33** below shows a range of peak mitigation based on residential customer battery uptake scenarios (by 2035) that assume optimal utility level control. These are illustrative estimates based on the 5 kW batteries utilized in the SGNS project, should those batteries be able to discharge their full capacity to the grid (in practice the available demand reduction would be lower than shown).

[22] https://www.zdnet.com/home-and-office/energy/best-home-battery/ estimate of $12000-$20000 USD installed.

Figure 33: Potential Peak Impacts from Batteries

Technology	Residential Share (%)			
	50%	**25%**	**10%**	**5%**
Battery Peak Impact - No Control (MW)	0	0	0	0
Battery Peak Impact - Optimal DR Control (MW)	(1,403)	(702)	(281)	(140)

The impacts of technologies related to direct load control (DLC) of heating and hot water loads are discussed in **Section 10**.

4.4.6 Intensities

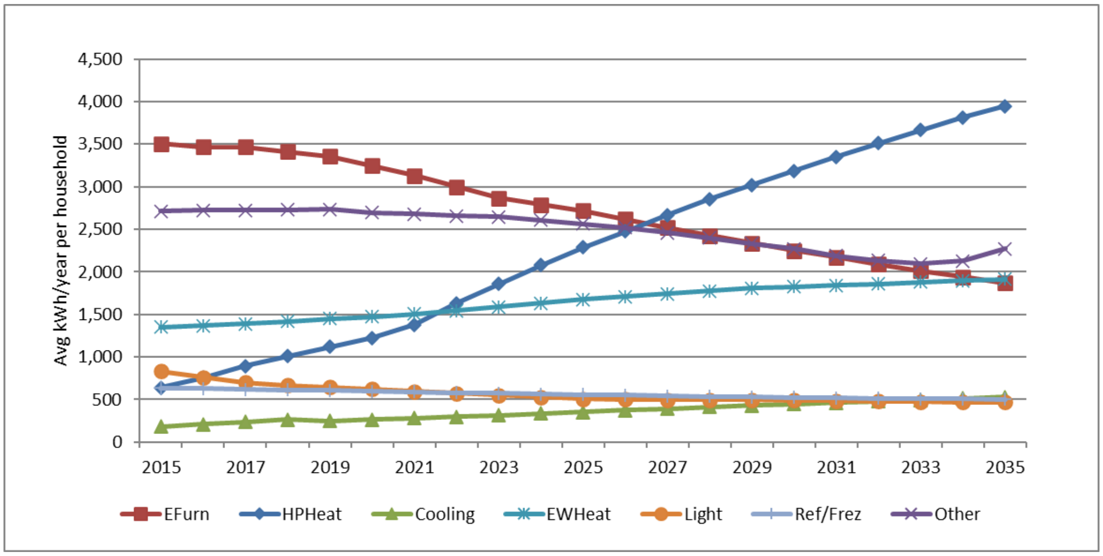
Figure 34 provides an estimate of the resulting residential end-use intensities. This figure represents the intensities that are inputs to the XHeat, XCool and XOther variables; they are not direct inputs to the forecast. The relative contribution of each will change based on the coefficient applied to the XHeat, XCool and XOther variables.

PV and EV are modeled outside the regression but are estimated in the "Other" category below in order to illustrate their impact relative to other end uses. A summary of the impact of the different variables post-regression is included in **Section 5**, while a complete breakdown of each element before and after the regression is provided in **Appendix B**. The end uses listed include:

- EFurn: electric baseboard and electric forced air furnaces and secondary electric heaters
- HPHeat: heat pump electric heat
- Cooling: room and central air conditioners, as well as heat pump cooling
- EWHeat: electric water heaters
- Lights: indoor lighting
- Ref/Frez: primary and secondary refrigerators and deep freezes

- Other: all other major appliances (stoves, dishwashers, clothes washers and dryers, televisions) as well as smaller appliances such as computers, dehumidifiers, microwaves, etc. This category also includes solar generation (photovoltaic or PV) and EV forecasts.

Figure 34: Residential End-Use Intensities

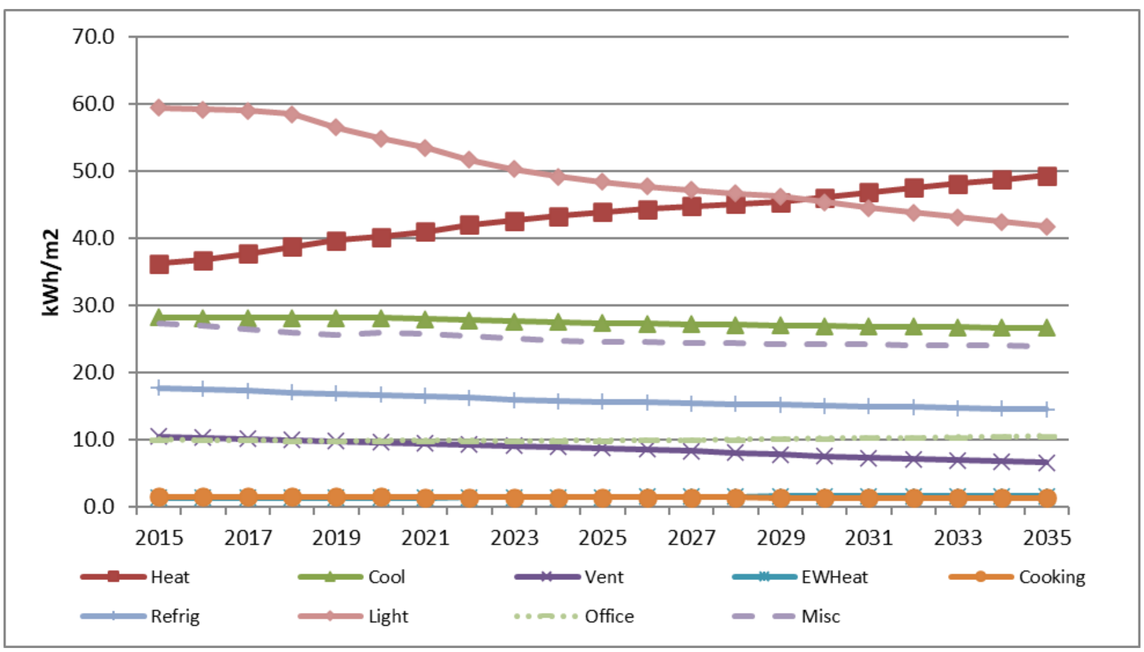


The intensity trends are similar to those in prior forecasts. The use of heat pumps for space heating is forecast to increase steadily throughout the forecast period including the conversion of both electric baseboard and non-electric homes. Offsetting this increase is a corresponding decrease in electric baseboard heating. Heat pumps also drive an increase in cooling intensity, but not during periods of peak demand. Electric water heating is expected to increase slowly as saturation increases, mainly due to conversions of non-electrically heated households to heat pumps. Lighting and refrigerators/freezers show a slow decline related to natural increases in efficiency. The forecast in the "Other" category declines over the forecast period due mainly to reduced assumptions around EV sales and increased PV generation. Supporting data for the residential end-use intensities is included in **Attachment 1**.

The end-use intensities for the commercial models are done on a per square metre basis, rather than per customer. The forecasts for the end-use intensities are set out in **Figures 35** and **36** below. The end uses listed include:

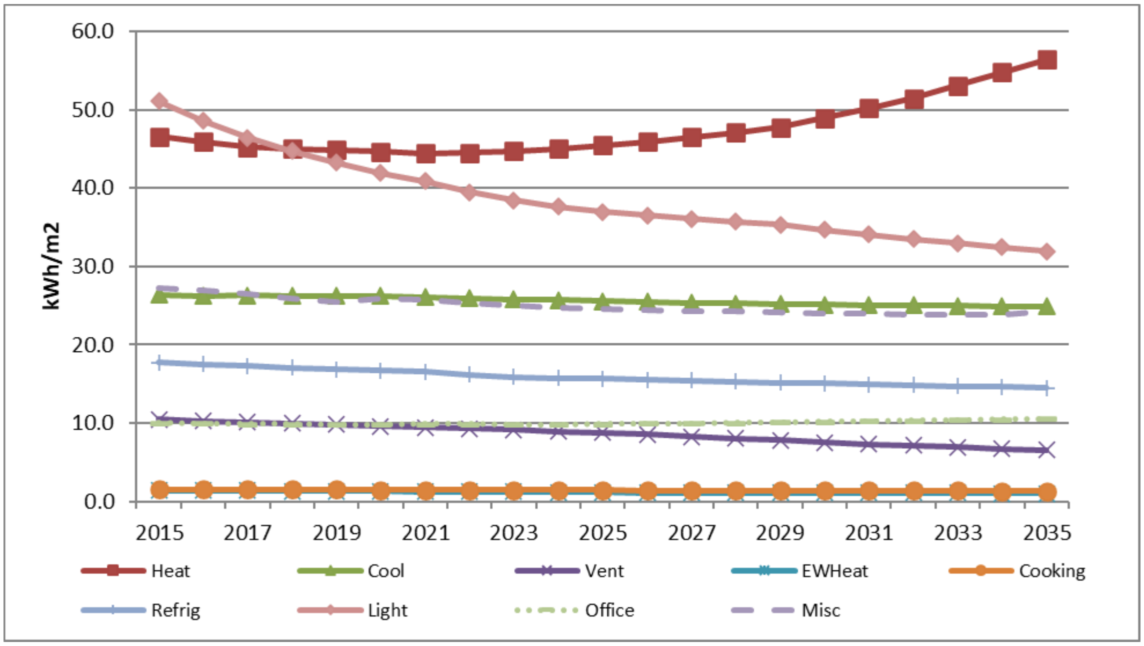
- Heat: electric heating
- Cool: air conditioning
- Vent: ventilation
- EWHeat: electric water heaters
- Cooking: electric stoves
- Refrig: refrigerators and freezers
- Light: indoor and outdoor lighting
- Office: computers and printers
- Misc: other loads including motors, servers, escalators, medical equipment, etc.

Figure 35: Historical and Projected Small General Commercial End-Use Intensity (kWh/m^2)



Supporting data for Small General commercial end-use intensities is included in **Attachment 2**.

Figure 36: Historical and Projected General Commercial End-Use Intensity (kWh/m²)



Supporting data for General commercial end-use intensities is included in **Attachment 3.**

For the 2025 Load Forecast, data from the EIA 2021 Annual Energy Outlook uses the same baseline data (2015 Residential Energy Consumption Survey and 2012 Commercial Building Energy Consumption Survey) as the 2024 Load Forecast. Small scale solar and EV load have been included in the Miscellaneous category.

4.4.7 Commercial and Industrial Growth

The commercial and industrial sectors are projected to see targeted growth as a result of the federal and provincial push to net-zero emissions and the resulting electrification programs designed to reduce customers' annual energy usage and lower their carbon emissions. These programs involve converting heating loads to electricity (mainly from oil), accelerating the uptake of electric cooling technologies, and examining opportunities to power industrial processes through electrification. Large Industrial customers are evaluated on a case-by-case basis to try to enable the use of electricity while providing benefits to the system (such as through the interruptible rider).

Forecasts by class (including new projects in the Large General and Large Industrial classes) are shown in **Figure 37**.

Figure 37: Commercial and Industrial Electrification Forecasts (cumulative)

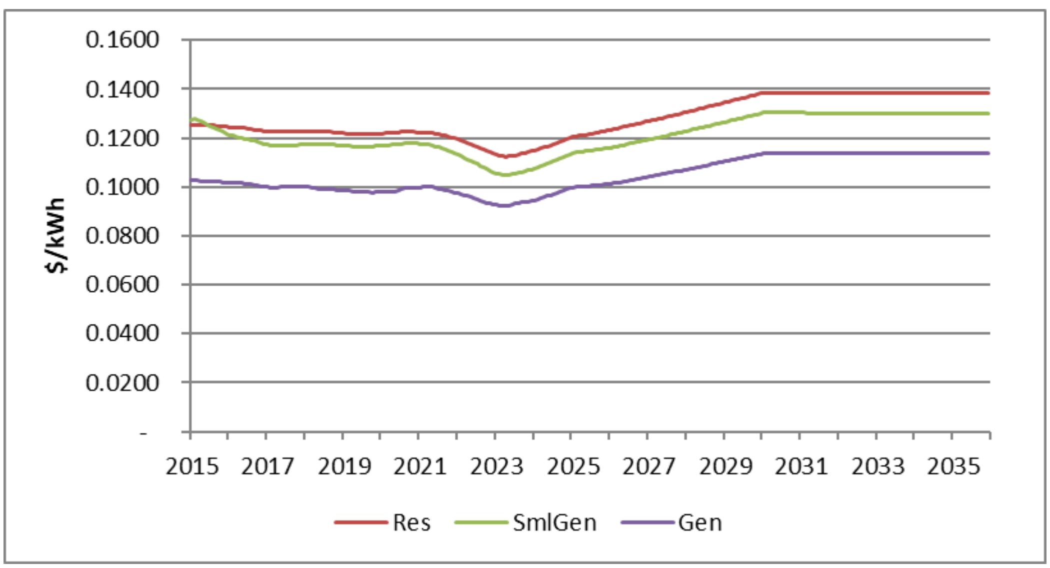
Year	LrgGen (GWh)	SmInd (GWh)	MedInd (GWh)	LrgInd (GWh)	Coinc. Peak (MW)
2025	3	1	3	2	0
2026	6	1	4	2	0
2027	10	1	6	3	1
2028	12	1	8	3	1
2029	14	2	9	4	2
2030	15	3	11	6	2
2031	16	3	12	5	3
2032	18	4	14	6	3
2033	19	4	15	8	4
2034	19	4	15	8	4
2035	19	4	15	8	4

4.5 Price Data

Price data is an input to the SAE forecasts for the residential, small general and general services classes, and the price series is calculated from historical billed sales and billed revenues. Revenue per kWh is first calculated and translated to a real dollar basis; the price variable itself is then derived as a 12-month moving average of the real revenue per kWh series. The 12-month moving average uncouples the current month sales/revenue relationship, smooths out the price series, and provides a reasonable expectation as to how customers respond to price over time.

In the forecast period, the nominal price of electricity for 2025 is based on an average increase of 3.8 percent as a result of the addition of the AA and storm riders, as well as the updated DSM rider.[23] From 2026 to 2029 prices are assumed to increase 5 percent on average, with increases of 2 percent per year (approximately inflation) thereafter. **Figure 38** shows price forecasts by class.

Figure 38: Historical and projected real electricity prices (real dollars per kWh)



Prices impact the class sales through imposed price elasticities. The SAE models are estimated using a price elasticity of -0.15. Another item raised in the NSUARB decision is to "continue to

[23] M11902, Exhibit N-21 NSPI (IG) RIR – 2 to 13 – Redacted I Refiled (further update to IG IR-06 Part b)

test the TVP elasticity in the load forecast as the elasticity changes over the course of the TVP Pilot."[24] The TVP Pilot estimates two elasticities:[25]

- Own/daily price elasticity captures the change in the level of overall consumption due to the changes in the average daily price.

- Substitution price elasticity captures customers' ability to substitute inexpensive off-peak consumption for more expensive peak consumption.

These elasticity estimations are based on subsets of customers (those enrolled in the TVP pilot) and represent changes in demand relative to hourly or daily pricing changes, and so are not necessarily directly comparable to the longer term time frame of the load forecast or to the population as a whole. The elasticity in the load forecast model represents changes in consumption behaviour in response to year-over-year price changes. The estimated elasticities for the two TVP rates are shown in **Figure 39**.

Figure 39: TVP Price Elasticity Estimates

Price Elasticity Metric	TOU	CPP
Daily Price Elasticity	-1.607 +/- 0.317	-0.017 +/- 0.173
Inter-Period Substitution Price Elasticity	-0.105+/- 0.005	-0.029 +/- 0.001

The elasticity values have changed significantly from the prior report, and although the Daily Price Elasticity for the TOU rate is significantly higher than that used in the load forecast, the Inter Period Substitution values are still similar to the value in the load forecast. In the SAE model the price elasticity does impact sales, but it is not a large driver compared to other components of the model such as the intensities or inputs like DSM and EVs. The current value of elasticity is reasonable to capture the impact on sales from changes in price.

[24] Nova Scotia Power Inc. 2024 Load Forecast Report, UARB Decision, October 22, 2024, page 7 (M11689).
[25] M11823 Time Varying Pricing Pilot Program Nova Scotia Power Year Three Evaluation Report, July 31 2024.

4.5.1 Demand Side Management

Demand Side Management (DSM) and conservation plans continue to play a role in the use of electricity in Nova Scotia, and the forecast takes the projected energy and demand savings into account. Between 2022 and 2025, DSM amounts are based on E1's proposed supply agreement.[26] Beyond 2025, DSM amounts are based on E1's 2019 Potential Study[27] base case scenario. These values are all in line with past assumptions about future DSM.

In order to highlight the impact of DSM in the province, the forecast amounts are subtracted from the results of the forecast regression models. As with other jurisdictions and utilities with significant DSM activity, NS Power must address the issue of double counting the impact of DSM savings. The forecast is a regression model based on sales which include past DSM activity, and past DSM also has an influence on other inputs to the load forecast such as price, end-use appliance efficiency and economic variables. Subtracting 100 percent of forecast DSM activities results in a model that understates sales because it has taken DSM into account in both the regression (via the historic data) and in the projected end-use data. The effect of DSM on non-sales related inputs also makes it unrealistic to add historic DSM into past sales to produce a "without DSM" forecast – the impact of DSM would have to also be removed from price, overall appliance efficiency and provincial economics.

To address the issue of double counting, the approach used is the same as that used in prior forecasts: to introduce cumulative historical DSM savings as reported by E1 to the regression model as a load modifying variable and allow the model to determine what level of DSM is already included in other variables. Assuming future DSM activities are similar to historic activities, the coefficient applied to historic DSM will also apply to the forecast DSM. This does not imply that a portion of DSM activities is not taking place or that forecast DSM is overstated; rather, it is a way of accounting for DSM that is captured elsewhere in the forecast. The methodology is not specific to DSM and could be applied to other variables that need to be highlighted in the forecast

[26] M10473, EfficiencyOne 2023-2025 DSM Resource Plan Filing, March 11, 2022.
[27] M08929, Exhibit N-1, EfficiencyOne, DSM Potential Study, August 14, 2019.

provided they have similar characteristics (historical trend, potentially included in other inputs, and some information about future impact).

In the Residential model, adding the historic DSM improves the fit of the Residential model (R squared of 0.989 vs 0.988 without the DSM variable, and a mean absolute percent error (MAPE) of 2.05 percent vs 2.13 percent without the variable). By including this variable, the corresponding coefficient, as determined by the regression model, is an indication of the amount of DSM not captured by the other variables. If the coefficient is -1, no DSM is included in other variables, or in practical terms the regression model determined 100 percent of the DSM savings were required to explain the annual change in historical load levels. If the coefficient is 0, 100 percent of the DSM is included in other variables. As can be seen in the Residential model results, the coefficient on the DSM variable is -0.414 (similar to prior values) meaning 58.6 percent of savings are already accounted for in the regression, and 41.4 percent are not captured by other variables, and need to be included in the forecast.

For the Commercial and Industrial classes, a combined model was created to identify the level of DSM already captured by other variables. DSM impacts are not provided for Commercial and Industrial customers by rate class or by month, so by creating a combined model for these classes, the level of uncertainty around allocating historical DSM savings across rate classes and months of the year is reduced. The DSM variable coefficient is similar to prior years: -0.433, meaning future years in the load forecast should be adjusted by 43 percent of the forecast DSM amounts. The adjusted R-squared for the model is 0.84 while the MAPE is 2.69, indicating a good fit overall. **Figure 40** shows the DSM levels (at the generator) incorporated into the forecast.

Figure 40: Annual Forecast Residential DSM Savings (incremental)

Year	Forecast Residential DSM savings (GWh)	Forecast Commercial DSM savings (GWh)	Forecast Industrial DSM savings (GWh)	DSM captured by Residential end use forecast (GWh)	DSM captured by Comm/Ind end use forecast (GWh)	DSM Adjustment for Residential with Coefficient (GWh)	DSM Adjustment for Comm/Ind with Coefficient (GWh)
2025	65.6	71.3	12.6	38.5	47.6	27.2	36.3
2026	69.6	56.7	10.0	40.8	37.8	28.8	28.9
2027	71.6	55.7	9.8	41.9	37.2	29.6	28.4
2028	73.0	62.9	11.1	42.8	42.0	30.2	32.0
2029	73.7	52.2	9.2	43.2	34.8	30.5	26.6
2030	73.3	51.0	9.0	43.0	34.0	30.3	26.0
2031	74.1	48.0	8.5	43.4	32.1	30.7	24.5
2032	73.2	46.8	8.3	42.9	31.2	30.3	23.8
2033	71.3	43.4	7.7	41.8	28.9	29.5	22.1
2034	69.1	44.0	7.8	40.5	29.4	28.6	22.4
2035	66.0	42.5	7.5	38.7	28.3	27.3	21.6

The methodology used to determine the DSM coefficient only works for levels of DSM that have been relatively consistent throughout the historical data set and does not imply that only a portion of future DSM will impact sales. If forecasts for DSM change significantly then this methodology will have to be revisited. One potential approach might be to treat net new incremental levels of DSM (those above the historical norm) as not being embedded in the forecast variables and subtracted at 100 percent for a period of time, but this will have to be evaluated with any proposed change to DSM levels.

A breakdown of the impact of DSM by class is provided in **Section 9**.

4.6 Renewable to Retail

One application has been submitted by a third party to the NSUARB for approval as a Licensed Retail Supplier (LRS) to provide service under the RTR tariffs starting in 2026.[28] The service is

[28] The effective date for sales from a retail supplier to a retail customer to commence under s.3C(1) of the Electricity Act has not been set. As such, a Retail Supplier licence issued by the NSUARB included a condition that no sales can occur before the effective date prescribed by the Governor in Council. In addition, it was a condition of the license

forecast to produce 500 GWh of energy through wind production when fully operational in 2027, and will serve approximately 420 GWh of load with 28 percent serving residential customers, 42 percent serving commercial customers, and 30 percent serving industrial customers. The corresponding energy amounts have been subtracted from the forecast starting in 2026 as outlined in **Figure 41**. Although load will be migrating from the various customer classes to the RTR market, part of the energy required to supply those customers will be provided by NS Power as top-up under the Energy Balancing Service tariff (approximately 140 GWh). The peak forecast remains unchanged as NS Power is required to serve the full peak of these customers if needed.

Figure 41: RTR Forecast by Class

Class	2026 Impact (GWh)	2027+ Impact (GWh)
Residential	40	117
Small General	1	3
General Demand	56	165
Large General	3	8
Small Industrial	3	10
Medium Industrial	29	84
Large Industrial	12	34
Total	**144**	**421**

issued by the NSUARB that if no electricity is sold to a customer under the authority of the license by December 31, 2024, the Licensed Retail Supplier must apply to the NSUARB to show cause why the licence should not be cancelled at that time (M10293). On April 30, 2024, the Licensed Retail Supplier sought an extension to December 31, 2025, which the NSUARB approved on May 30, 2024 (M10293). Then on November 1, 2024, the Licensed Retail Supplier sought an additional extension to December 31, 2026, which the NSUARB approved and issued an amended Retail Supplier licence under the Electricity Act, S.N.S. 2004, c. 25, s. 3E(2) on November 12, 2024 (M10293).

5.0 RESIDENTIAL SECTOR

The Residential sales forecast is generated as the product of a residential average use forecast and a customer count forecast. The residential average use model is specified using a SAE model structure and the customer count forecast is based on forecast housing completions. Full details on the residential SAE model can be found in **Appendix B** and in **Attachment 5**. As outlined in **Section 4.4**, projections for EVs and residential solar are added to the modeled load projection. New customers are also added outside of the model.

On a weather normalized basis, residential sales grew by 2.1 percent between 2023 and 2024 due to continued work-from-home activity, increased number of new customers, and an increased number of heat pumps. **Figure 42** shows a breakdown of the different components for 2022, 2023 and 2024 actuals vs forecast and weather normalized totals, and the 2025 forecast.

Figure 42: Comparison of Forecast to Actuals

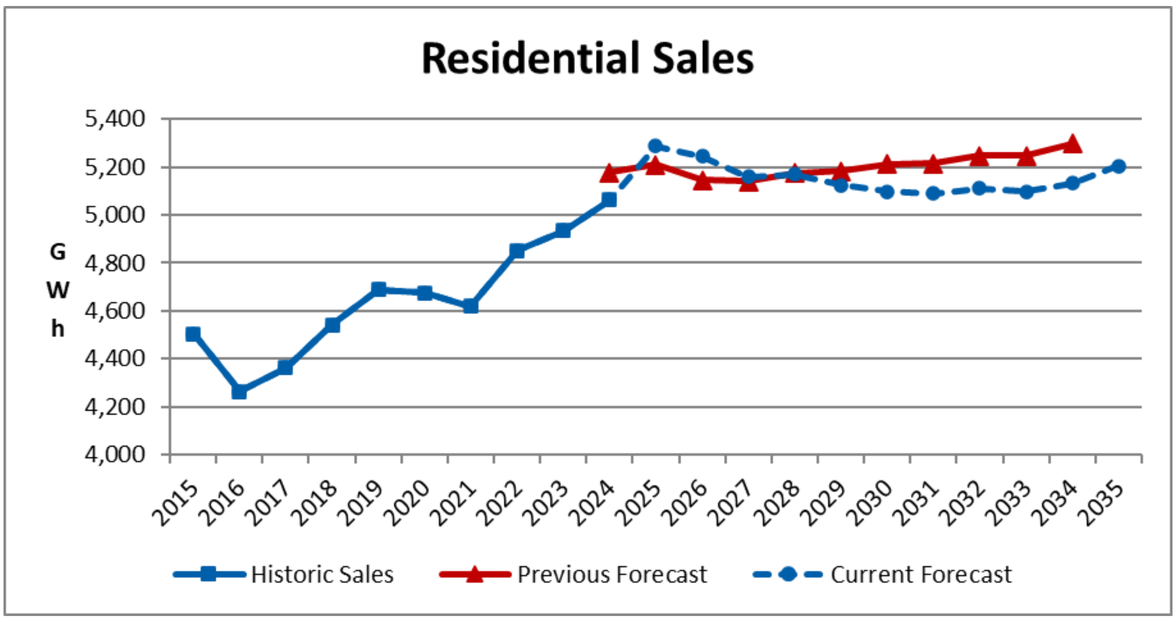
Year	2022	2023	2024	2025
Forecast Sales	4715	4830	5180	5289
Weather variance	-127	-126	-104	-
Other variance	+263	+230	-12	-
Actual Sales	4851	4934	5064	-
Weather-adjusted sales	4978	5060	5167	5289

As discussed in the 2024 forecast, adjustments were made to heating intensities last year to better capture the trends seen in 2022 and 2023 that led to high “Other” variances. In 2024 those adjustments have helped reduce the “Other” variance substantially.

The COVID-19 variable that was added in 2020 continues to be used for the years 2020-2024, but has been removed from the forecast years. The variable helps to explain changes in consumption patterns over the 2020-2024 time period, but it is expected that these changes are sufficiently captured by the other model variables in future years and a separate variable is not needed in the forecast period.

Weather adjusted sales in 2024 were very close to forecast, though the warm weather reduced sales in the class by 104 GWh. 2026 and 2027 are expected to decline as a result of load migrating to the RTR market, with a declining trend through 2033 due to increased behind the meter solar adoption. After 2033, EV load is expected to start increasing sales. As with previous forecasts, new customers and increased electric heating will increase sales, while DSM and naturally occurring efficiency improvements will decrease sales over time. Over the 2025-2035 period, forecast sales in this class decrease 0.2 percent annually. Historical and forecast annual residential sector loads are shown in **Figure 43**.

Figure 43: Historical and Forecast Annual Residential Sales



The forecast for new construction in 2024 was 7,021 units, while actual customer growth was 7,800. Nova Scotia's population continues to increase (see **Figure 13**) through immigration from abroad and from other provinces, but with reduced federal immigration targets the forecast from the Conference Board of Canada is lower than in 2024, with a forecast of 21,000 more people in the province between 2024 and 2035 compared to 60,000 over the same period in the 2024 forecast. New housing is expected to be over 58,000 new units by 2035, with 36,700 new multi-unit residences and 21,800 single family homes.

In prior forecasts single-family homes were assumed to use approximately 16,000 kWh per year on average, while multi-unit homes were assumed to use 4,860 kWh per year on average. Using AMI data, a study was conducted to compare electricity consumption trends among single-family units (SFU) and dwellings within multi-unit residential buildings (MURB). Overall, SFU properties consume approximately three times as much electricity as MURB units. A subset of premises in the study also had data available on year of construction, allowing for further classification into:

- Old Buildings: Constructed before 2015
- New Buildings: Constructed in 2015 or later

Figure 44 summarizes the average annual electricity consumption for MURB and SFU properties based on these categories.

Figure 44: Annual Consumption by Building Type

Property Type	MURB (kWh/year)	SFU (kWh/year)	Number Sampled
New Buildings	4,101	14,626	18,443
Old Buildings	5,617	12,314	234,576

Figure 44 indicates a decreasing trend in electricity consumption for MURB properties over time, while SFU properties show an increase. Differences in electricity consumption between old and new MURBs may stem from various factors. New construction typically incorporates modern energy-efficient technologies and materials—such as enhanced insulation, energy-efficient windows, and advanced heating and cooling systems—that collectively reduce energy usage. Additionally, features like smart home technologies can further optimize energy consumption. In contrast, older buildings often lack these advancements, relying on outdated, less efficient systems that lead to higher energy consumption. Poor insulation and inefficient heating systems in such buildings necessitate more energy for heating. While renovations and retrofits can enhance the energy efficiency of older structures, they may still fall short of the standards set by newer constructions. However, increased electricity consumption in new single-family units (SFUs) can

be attributed to factors such as larger living spaces and a greater concentration of electric space and water heating compared to older buildings. Despite improvements in energy efficiency, these factors can lead to an overall rise in electricity demand in new SFUs.

In terms of magnitude, MURB units saw the largest change, with a 27 percent decrease in consumption, while SFU properties experienced a 19 percent increase. The updated reduction in new customer load is offset by higher new customer counts in the current forecast when compared with 2024.

In addition to using these annual averages, a structural index was applied that considers building shell efficiency (BSE from the EIA forecast) as well as projected changes in house size. Building efficiency is expected to improve, although based on calibration done in 2013, improvements are expected to be lower in Nova Scotia than in the EIA forecast for New England. While efficiency is expected to increase, house size is also expected to continue increasing, albeit at a slower rate than in previous years. These two factors combined lead to a steady average use per new residential customer. Building shell efficiency, floor area and the resulting structural index are in **Figure 45.**

Figure 45: Building Characteristics and Structural Index

Year	**BSE Heat EIA (New England)**	**BSE Heat NS**	**Floor Area (m^2)**	**Structural Index**
2025	0.920	0.967	153.2	1.000
2026	0.914	0.965	153.5	1.001
2027	0.908	0.964	153.8	1.001
2028	0.901	0.962	154.0	1.001
2029	0.895	0.959	154.3	0.999
2030	0.888	0.957	154.5	0.998
2031	0.881	0.954	154.6	0.996
2032	0.874	0.951	154.7	0.994
2033	0.868	0.949	154.8	0.993
2034	0.862	0.948	154.9	0.992
2035	0.857	0.947	155.0	0.991

Figure 46 provides a breakdown of the components of the Residential forecast at the system level. Please refer to **Appendix B** for tables with a detailed breakdown of the changes from 2025 to 2035.

Figure 46: Residential Sales Components by Year

Year	**Regression Model Output (GWh)**	**New Cust. (GWh)**	**Hybrid Adjust. (GWh)**	**Solar Impact (GWh)**	**EV Impact (GWh)**	**RTR Sales (GWh)**	**DSM Adjust. (GWh)**	**Total Sales (GWh)**	**Total Res. DSM [29](GWh)**	**DSM captured by end uses [30](GWH)**
2025	5268	62	0	-27	11	0	-24	5289	-59	-35
2026	5283	120	-25	-59	16	-40	-50	5246	-122	-72
2027	5299	175	-50	-95	24	-117	-77	5159	-186	-109
2028	5342	227	-75	-136	33	-117	-104	5170	-252	-148
2029	5335	275	-100	-184	46	-117	-131	5125	-318	-187
2030	5355	317	-125	-239	65	-117	-158	5098	-384	-226
2031	5398	351	-140	-308	92	-117	-186	5090	-451	-265
2032	5463	383	-156	-382	133	-117	-213	5112	-517	-304
2033	5486	413	-171	-467	194	-117	-240	5098	-581	-341
2034	5529	440	-186	-556	287	-117	-265	5132	-643	-378
2035	5570	464	-202	-650	429	-117	-290	5206	-703	-413

Figure 47 provides an approximation of the heat pump heating, heat pump cooling, electric baseboard, and water heater loads at the system level (these are included in the Regression Model Output column). This approximation uses the same methodology as outlined in the response to NSUARB IR-12 (e) from the 2020 Load Forecast, where the end-use intensity is multiplied by the number of existing customers, the appropriate X coefficient from the regression model, and either the HeatUse variable or the CoolUse variable (see **Appendix B** for details of these components). As this assumes that the X variables apply equally to all end uses, which may not be the case, the numbers are illustrative only. These numbers also do not include any DSM amounts that would impact the specific end use.

[29] Total DSM is the amount from Figure 20, adjusted for losses and with approximately 0.4 percent allocated to the Municipal class customers.

[30] These amounts are embedded in the Regression Model Output column through the end use efficiency estimates (i.e. the amount not captured by the DSM coefficient).

Figure 47: Illustrative Contribution of Specific End Uses

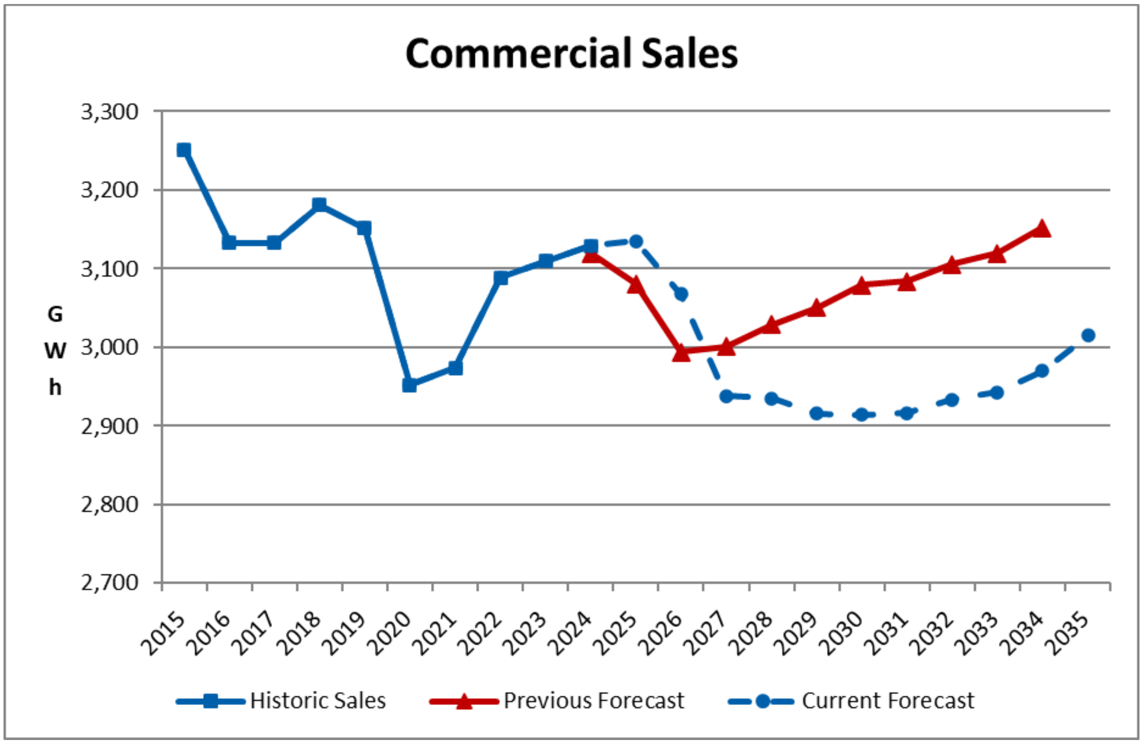
Year	HP Heat (GWh)	HP Cool (GWh)	Baseboard Heat (GWh)	Water Heat (GWh)
2025	1142	163	1025	792
2026	1222	174	955	802
2027	1298	184	886	811
2028	1381	194	828	823
2029	1440	203	764	830
2030	1505	214	708	833
2031	1574	224	662	840
2032	1653	234	617	850
2033	1709	245	567	855
2034	1773	255	524	864
2035	1827	265	483	872

6.0 COMMERCIAL SECTOR

The Commercial SAE model creates a unique forecast for the Small General and General rate classes. Like the residential model, the commercial SAE models express monthly sales as a function of heating, cooling, and other loads. The Small General forecast is based on a monthly SAE average use model and a separate customer forecast. The General rate class model is estimated on a total monthly sales basis (class level sales vs customer level) where total monthly billed sales is a function of total monthly heating requirements, cooling requirements, and other use. The end-use variables are constructed by interacting annual end-use intensity projections that capture end-use intensity trends, with GDP and employment, real price, monthly HDD and CDD and a variable accounting for the number of days in each month. As discussed in the introduction, employment by sector has been added to the commercial intensity models to calibrate the underlying NRCan data for the Atlantic provinces to Nova Scotia specifically.

A detailed breakdown of the two commercial SAE models is provided in **Appendix B** and in **Attachments 6** and **7**. Although sales were negatively impacted by the COVID-19 pandemic in 2020 and 2021, commercial sales rebounded in 2022 along with the economy, and grew in 2023 (though less than forecast). **Figure 48** shows the drop in 2020 and 2021 followed by the rebound in 2022. The COVID variable that was used in the General rate class model in prior years has been removed in the 2025 forecast as the historic data captures the impact to sales.

Figure 48: Commercial Class Sales

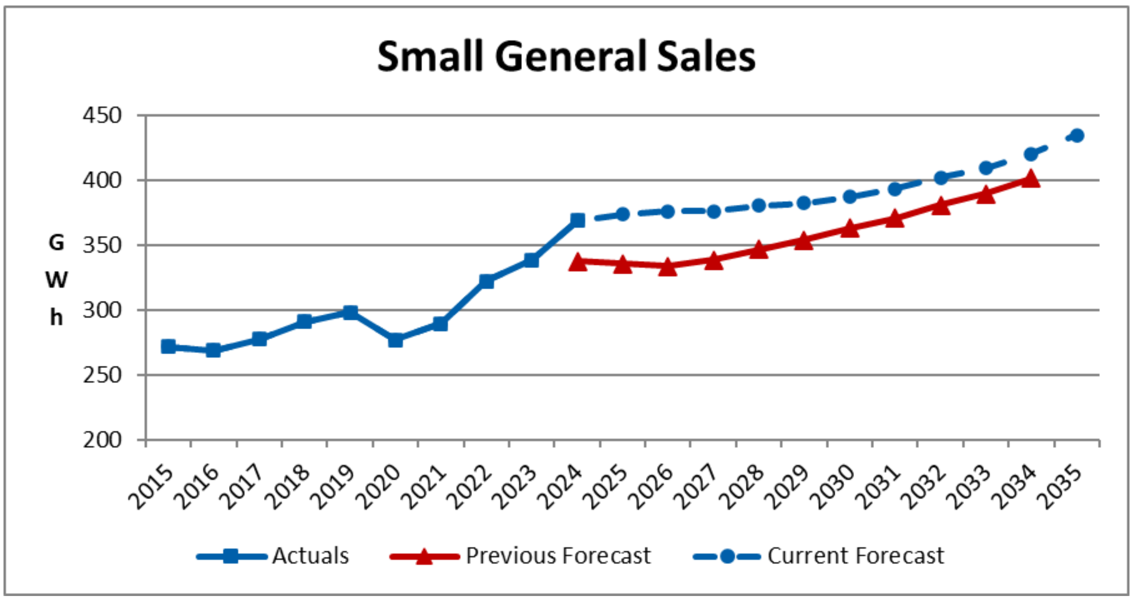


For 2025, the impact of RTR has increased (-176 GWh compared to -112 GWh in the 2024 forecast), as has the impact of solar (-263 GWh by 2035 compared to -246 GWh in the 2024 forecast) and the EV load has decreased (+285 GWh by 2035 compared to +302 GWH in the 2024 forecast), resulting in lower growth than the previous forecast.

6.1 Small General Service

Historical and forecast Small General service loads are shown in **Figure 49**. Small General service load shows an average annual increase of 1.5 percent compared to an increase of 1.8 percent per year in the 2024 Load Forecast. Commercial electrification of heating will be offset by a combination of DSM and decreased intensity forecasts for the ventilation, lighting and miscellaneous end uses. As with the 2024 Load Forecast, the heating penetration from the residential class was used as the end-use intensities are similar.

Figure 49: Historical and Forecast Annual Small General Sales

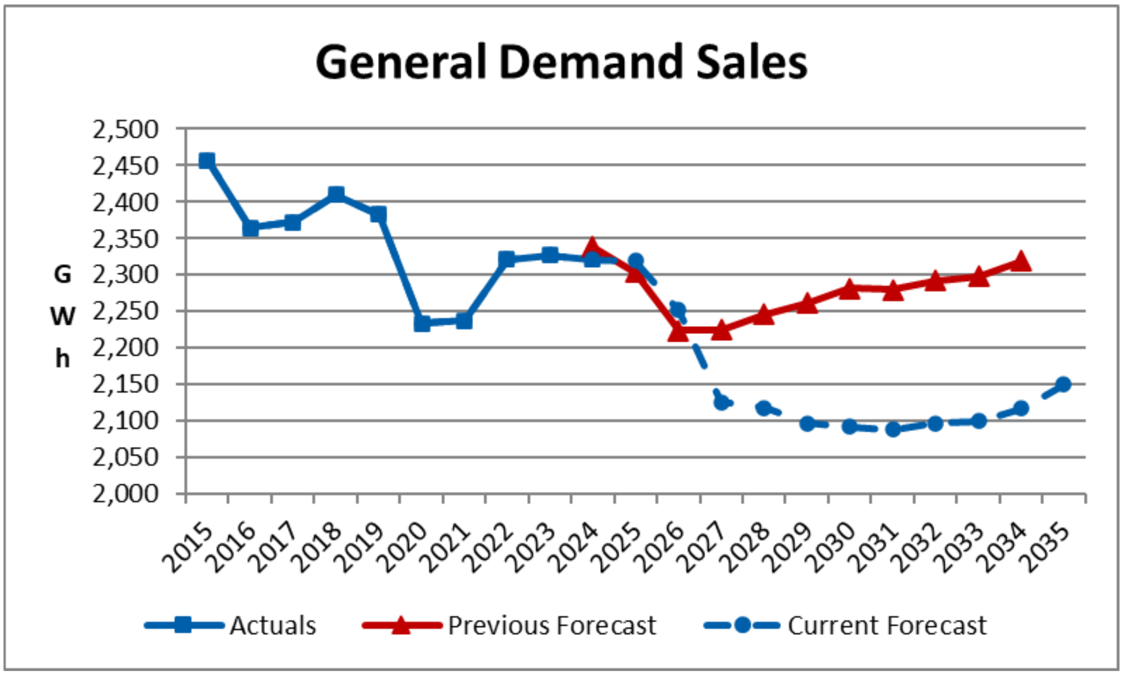


Please refer to **Appendix B** for tables with a detailed breakdown of the changes from 2025 to 2035. Total change between 2025 and 2035 is an increase of 16.3 percent.

6.2 General Service

Historical and forecast General class sales are shown in **Figure 50**. General class load is expected to decrease by 0.8 percent per year during the 10-year forecast period, compared to a decrease of 0.1 percent in the 2024 Load Forecast. The primary changes to the forecast include lower EV load as well as the commercial energy impact of the hybrid heating scenario. Increased space heating will continue to be offset by DSM programs as well as increased efficiency of the lighting and miscellaneous end uses. A drop in sales in 2026 and 2027 is related to sales shifting to the RTR market (-165 GWh per year), and higher solar generation will reduce sales by a further 237 GWh by 2035.

Figure 50: Historical and Forecast Annual General Demand Sales



Please refer to **Appendix B** for tables with a detailed breakdown of the changes from 2025 to 2035. Total change between 2025 and 2035 is a decrease of 7.3 percent.

6.3 Large General Service

The Large General class forecast is similar to the 2024 forecast. The forecast uses a combination of customer survey and historical sales information. Customers are surveyed annually to determine their electricity requirements over the next three-year period. In addition, NS Power personnel are in regular contact with key customers within this class. Details on planned production levels or equipment changes help inform energy requirement expectations. In the absence of survey or publicly available information, load levels are forecast to be flat before the impact of any DSM activities.

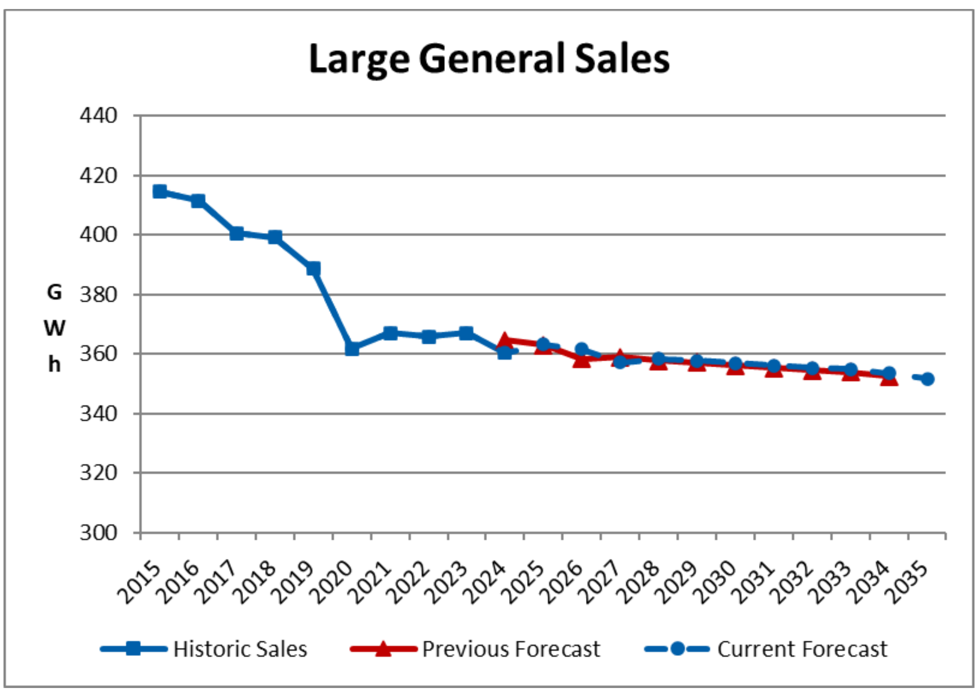
For the 2025 survey, five customers indicated no change to consumption, nine indicated an increase and five did not respond. Growth in this class is expected to be driven by institutional facilities, in particular expansions at several hospital sites in the province. The forecast for customer growth related to new projects/expansions is provided in **Figure 51**.

Figure 51: Large General Annual Growth (GWh)

Year	2025	2026	2027	2028
2025 Forecast	3	3	4	0

The overall forecast has a decrease of approximately 12 GWh by 2035 as shown in **Figure 52**. The decline is due to DSM outweighing projected growth.

Figure 52: Historical and Forecast Annual Large General Sales



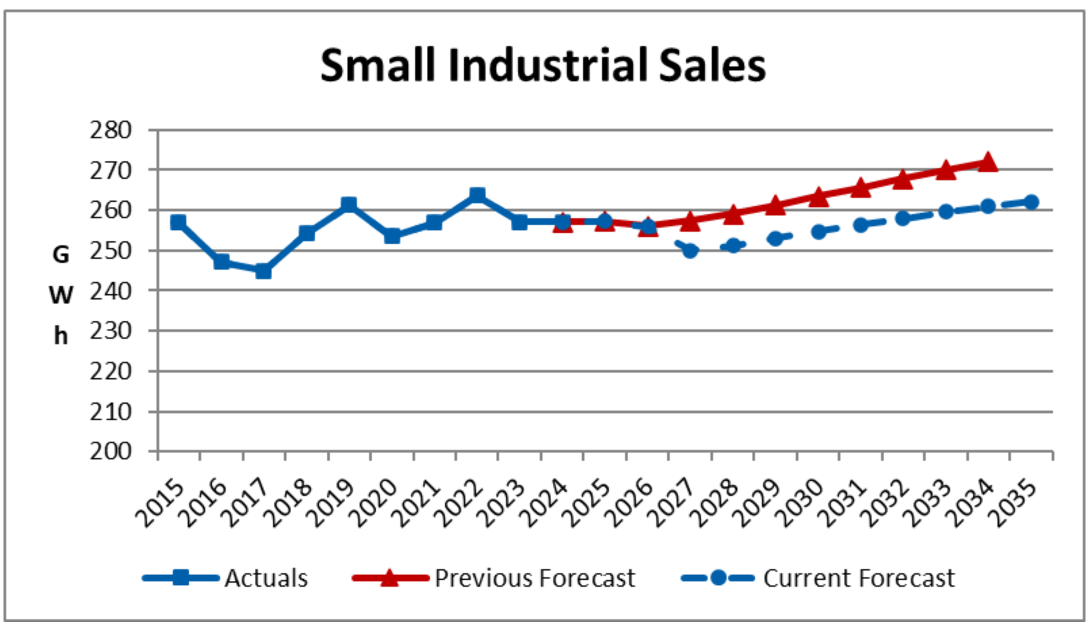
7.0 INDUSTRIAL AND MUNICIPAL SECTORS

The forecast models for the Small Industrial and Medium Industrial classes are econometric-based models (i.e. dependent on economic variables). Provincial manufacturing GDP is used as the primary economic variable in the Small Industrial forecast and manufacturing employment is used for the Medium Industrial class. The Small and Medium Industrial class models are developed using monthly sales information, as opposed to annual sales, in order to align the timeframes of industrial models with those of the residential and commercial forecast models. This is required in order to implement an end-use-based peak forecast for the commercial and residential sectors. Supporting data is included in **Attachments 8** and **9.**

7.1 Small Industrial

Figure 53 depicts historical and projected sales for the Small Industrial class. Sales in this class have been flat for the last 10 years and are expected to grow at 0.1 percent annually over the forecast period due to underlying economic growth offset by a migration of load to RTR (10 GWh).

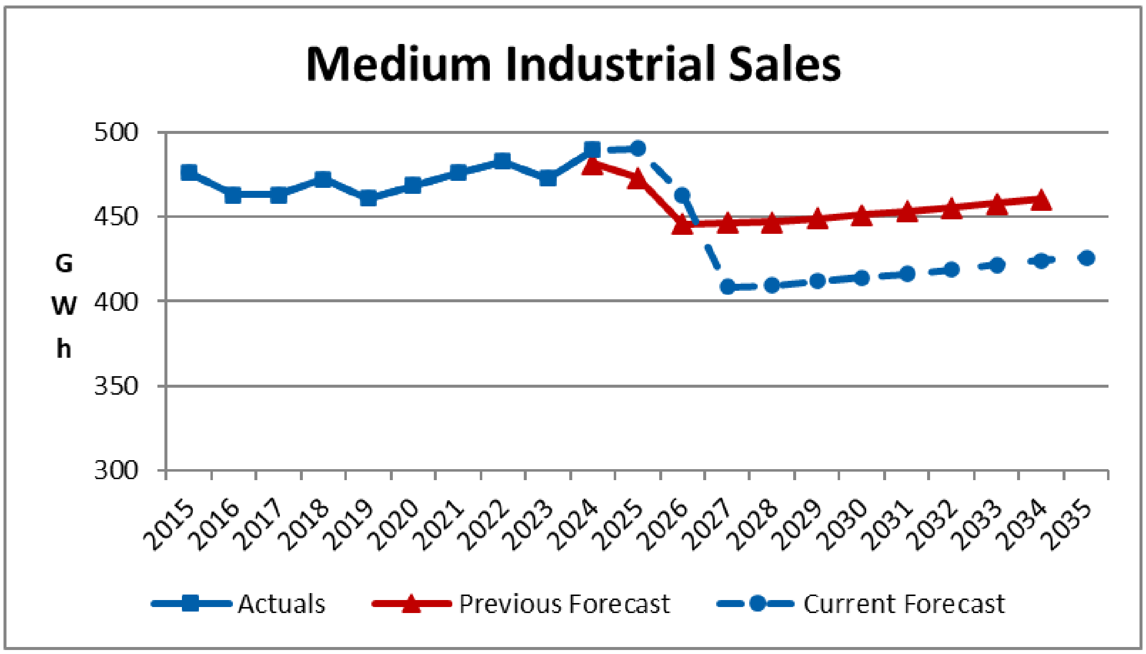
Figure 53: Historical and Forecast Annual Small Industrial Sales



7.2 Medium Industrial

Figure 54 depicts historical and projected sales for the Medium Industrial class. Load in this class has been flat since 2014. There was an increase in sales between 2019 and 2022 due to several new facilities ramping up production and minimal impact from the COVID-19 pandemic restrictions. Sales are expected to decline in 2026 and 2027 as load migrates to the RTR market (84 GWh), resulting in an average decline of 1.4 percent over the forecast period.

Figure 54: Historical and Forecast Annual Medium Industrial Sales



7.3 Other Industrial Rate Classes

Other Industrial rate classes include Large Industrial, Large Industrial Interruptible, Generation Replacement and Load Following, One-Part Real Time Pricing, Shore Power, and the Extra Large Industrial Active Demand Control tariff.

Like the Large General rate class, load for these rate classes is forecast using a combination of customer survey and historical sales information. Customers are surveyed regularly to gather their electricity requirements over the next three-year period. Details on planned production levels or equipment changes help inform expectations on energy sales. In the absence of any survey or general public information, load levels are forecast as being flat. For the 2025 survey, fifteen said energy consumption would remain the same, five indicated consumption would increase, one indicated a decrease, and nine customers did not respond. One customer makes up over [redacted] of sales within this class and is forecast to increase load by [redacted] in 2025 compared to 2024 actuals. Load migration to the RTR market is expected to be 34 GWh by 2027.

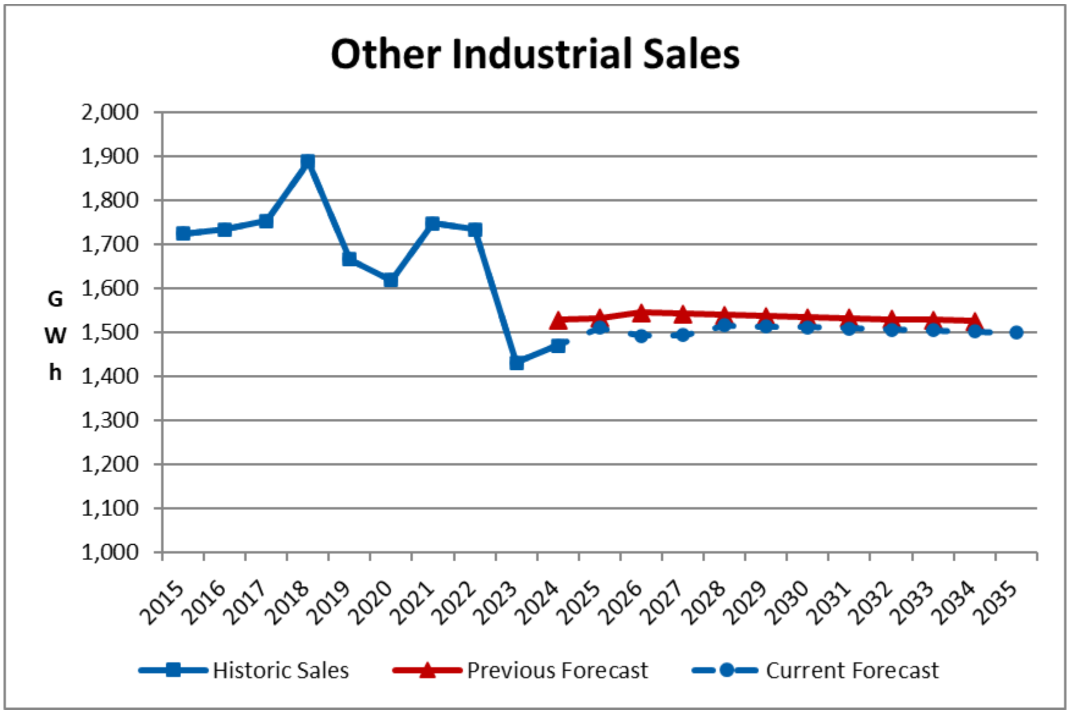
Although discussions with customers have indicated that several new facilities or expansions are expected in various industries in the coming years, there is uncertainty in the timing and magnitude of these changes. The forecast for customer growth related to new projects/expansions is provided in **Figure 55**.

Figure 55: Large Industrial Annual Growth (GWh)

Year	2025	2026	2027	2028
2025 Forecast	2	0	1	0

Figure 56 shows the historic and forecast sales for the Other Industrial sector.

Figure 56: Historical and Forecast Annual Other Industrial Sales



7.4 Municipal

The Municipal class comprises municipal electric utilities that purchase wholesale electricity from NS Power and distribute it within their own service territories. Utility loads within these municipalities include customers in residential, commercial and industrial sectors. Energy in this class also includes the losses incurred by the municipal utilities in meeting their electricity requirements.

Since 2007, the municipal electric utilities have been able to source their electricity from providers other than NS Power through the Open Access Transmission Tariff (OATT). Four municipal electric utility customers were sourcing approximately half of their energy requirement from suppliers other than NS Power, and in 2020 increased their energy purchases to 100 percent from third parties, resulting in a reduction in municipal load of about 150 GWh from historic levels. These customers have their load served by a combination of in-province generation and either the bundled municipal rate (2023 - 2025) or imported third-party generation in combination with energy under the Wholesale Market Backup/Top-Up (BUTU) Tariff in cases where their third-party supply is unavailable or interrupted. Their load is assumed to be served by a third party after 2025.

Because NS Power is required to provide back-up capacity, including reserve margin, to the municipal electric utilities taking third-party supply in the near term and must continue to plan for serving these customers in the long term, the full amount of the municipal electric utilities' peak demand is included in the Load Forecast.

8.0 SYSTEM LOSSES AND UNBILLED SALES

The difference between energy generated for use within provincial borders and the total NS Power billed sales comprises transmission and distribution system losses as well as changes to the level of unbilled sales. Energy generated and sold but not yet billed is referred to as “Unbilled” sales. System losses averaged 6.6 percent of NSR over the past five years and are forecast to remain in the 6.0 to 7.0 percent range over the 10-year forecast period.

9.0 NET SYSTEM REQUIREMENT

The NSR is the energy required to supply the sum of residential, commercial, and industrial electricity sales, plus the associated system losses, within the province of Nova Scotia. Loads served by industrial self-generation, exports, and transmission losses associated with energy exports are not included. **Figure 57** provides a breakdown of the significant variances between forecast and actuals for 2024.

Figure 57: 2024 Variance to Actual

	Res	Comm	Ind	Other	Losses	NSR
2024 Forecast	5,180	3,118	2,267	159	767	11,490
Est. Weather Impact	-104	-20		-3	-8	-134
Large Customer New Projects		-2	-3			-5
Large Customer Actuals			-56			-56
Unexplained Variance	-12	33	8	-12	15	36
2024 Actual	5,064	3,129	2,216	144	773	11,326

Note that the largest variances are due to weather and the variance in large customer actuals ([redacted] of which is related to a single customer). Like 2022 and 2023, 2024 was a very warm year overall, with 3,561 HDD compared to the 10-year average of 3,715. The weather impact captures both the variance in heating load in the winter months and the variance in cooling load during the summer.

From 2025 to 2035, NSR is forecast to decrease at an average of 0.2 percent per year, with growth driven by new customers, space heating and EV adoption, and with solar, DSM and RTR migration offsetting sales. Annual NSR is shown below in **Figure 58**. Forecast NSR values and the contribution to NSR from the different sectors can be found in **Appendix A**.

Figure 58: Historical and Forecast Annual NSR

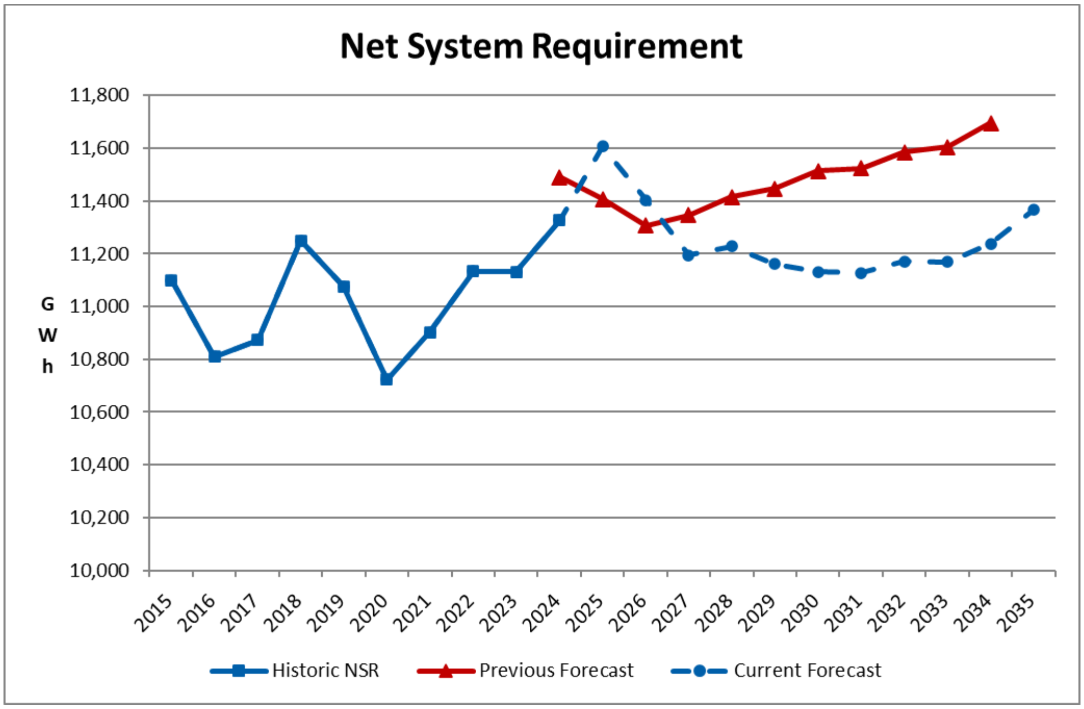


Figure 59 provides a breakdown of the various components of the change in the forecast from 2025 to 2035. Data for all classes is included in **Attachment 4.**

Figure 59: Forecast Components

GWh	Res	Comm	Ind	Other	Losses	NSR
2025 Forecast	**5,289**	**3,135**	**2,258**	**148**	**777**	**11,607**
Model	303	251	38	-77	28	544
New Customers	403	36				439
Solar	-622	-252				-875
EV	418	290				708
C&I Electrification		9	22			31
Large Customer Projects		9	50			43
Hybrid Model Adjustment	-202	-85				-287
RTR	-117	-176	-128	135		-269
DSM	-265	-202	-53	-3	-51	-575
2035 Forecast	**5,205**	**3,014**	**2,187**	**203**	**755**	**11,365**
Total DSM forecast	-700	-533	-94	-7	-122	-1,456
DSM captured in underlying models	-434	-331	-41	-4	-71	-882

10.0 PEAK DEMAND

The total system peak is defined as the highest single hourly average demand experienced in a year. It includes both firm and interruptible loads. Due to the weather-sensitive load component in Nova Scotia, the total system peak occurs in the period from December through February.

Since 2015 NS Power has employed an end-use approach to deriving the peak forecast. The breakdown of energy into heating, cooling, and other load components from the energy SAE forecasts is used as an input into the peak forecast. This allows for the impact of changing heating and cooling requirements, which drive the peak in most months, to be reflected in the peak forecast (but does not provide details of the specific underlying end uses). Details about the peak forecast model can be found in **Appendix B** and in **Attachment 10**.

With the updated peak contribution of EVs based on actual charging behaviour, specific peak mitigation for EV home charging is not included in the 2025 forecast. For 2025, the impact of the hybrid heating scenario modeled by E3 and used in the current Evergreen IRP models continues to be included (refer to **Figure 76**). The DR savings amounts included in the forecast continue to be based on the demand reduction amounts included in the 2022 Evergreen IRP. The individual programs within the 'Base' program are modeled and include Direct Load Control (DLC), Time Variable Pricing (TVP) and business, non-profit and institutional (BNI) Curtailment. The achievable potential of these programs was used in the Load Forecast. NS Power's IRP Action Plan targeted 75 MW of capacity for DR deployment by 2025. The estimates in the Load Forecast have been moved back to 2028 to align with the current program development and expected ramp-up for both DLC and CPP. DR forecasts continue to use an effective load carrying capacity (ELCC) of 48 percent to account for the fact that the full nameplate capacity will not be available at all times, and this value will be reassessed as more information is gathered through the implementation of DR programs. On February 6, 2025, NS Power distributed to stakeholders for review and comment a draft study scope document for the next ELCC study. The study scope identified DR as one of the areas of focus for the next ELCC study "using program details and measured results from NS Power's (CPP and TVP) and E1's current demand response programs."[31]

Annual DR totals by program are provided in **Figure 60**.

Figure 60: Demand Response

Year	Direct Load Control (MW)	TVP Rate (MW)	Business, Non-Profit & Industrial Curtailment (MW)	Total (MW)	Total with ELCC (MW)
2025	4	4	1	9	4
2026	12	12	2	26	12
2027	24	22	4	50	24
2028	36	32	6	74	36
2029	39	36	7	82	39
2030	39	35	6	81	39
2031	39	35	6	80	39
2032	39	34	6	79	38
2033	39	34	6	79	38
2034	38	33	6	78	37
2035	38	33	6	78	37

A pilot project was completed in 2021 and 2022 in conjunction with E1 to investigate direct load control through water heater controls. 201 water heater controllers were procured and installed in residential homes, and testing was completed to demonstrate the benefit of utility-managed load shift events. Results from the pilot, as presented in E1's 2023 Demand Response Program Final Report,[32] indicated that the average available DR capacity per controller during the utility winter peak period is 385 W. Results indicated that capacity tends to be lower during the last hour of a four-hour event. Results also indicated that available DR capacity per controller during mornings and evenings were 430 W and 359 W, respectively. This pilot project was put on hold for the 2023/2024 season following the removal of the installed hot water controllers due to quality concerns. New controllers were received in 2024, and installations are ongoing through E1's

[31] Effective Load Carrying Capacity (ELCC) Study Scope Memo, February 6, 2025.
[32] 2023 DSM Programs Evaluation Reports (M11630), March 28, 2024, Demand Response Program Final Report, Table 7, p.8.

Efficient Product Installation Program. 803 controllers were installed in 2024.[33] E1 integrated this pilot project into the Eco Shift program for the 2024/2025 season.

NS Power is also working with E1 on a two-phase pilot project to investigate automatic and manual control of various loads for commercial and industrial (C&I) customers. Customer recruitment was scaled up during 2023 for the 2023/2024 winter season, with the addition of 67 additional customers. Results from the winter 2023/2024 season, as presented in E1's 2024 DSM Programs Evaluation Report,[34] indicated total available DR capacity at the generator of 8 MW for the 76 participating C&I customers. DR capacity results for the winter 2024/2025 season are still being evaluated.

NS Power is also working with E1 on the Eco Shift pilot which involves directly controlling residential smart thermostats, EVs, EV chargers, and batteries. The two-year pilot was launched in December 2023 and recruitment of eligible smart thermostats, EVs, and EV chargers was completed. The residential DR Program achieved 0.1 MW of available capacity for the 2023/2024 season through the Eco Shift Pilot. The 2024/2025 Eco Shift season (December 1, 2024, to February 28, 2025) included the addition of hot water heater controllers, heat pump controllers and residential batteries. DR capacity results for the winter 2024/2025 season are still being evaluated.

As the DR projects in conjunction with E1 continue to progress, data collected will be used to inform forecast assumptions. Learnings from these pilots will be incorporated in future Load Forecasts. The impact of these initiatives, at least within the 10-year timeframe of this forecast, is expected to fall within the sensitivity analysis provided in **Section 11**. Like the interruptible load, DR programs are a resource that can be called upon if required, but they will not inherently reduce demand. In recognition of this, peak reduction from DR is included in the firm peak but is excluded from the system peak.

[33] 2024 DSM Annual Progress Report (M12186), March 31, 2025, p.36.
[34] 2024 DSM Annual Progress Report (M12186), March 31, 2025.

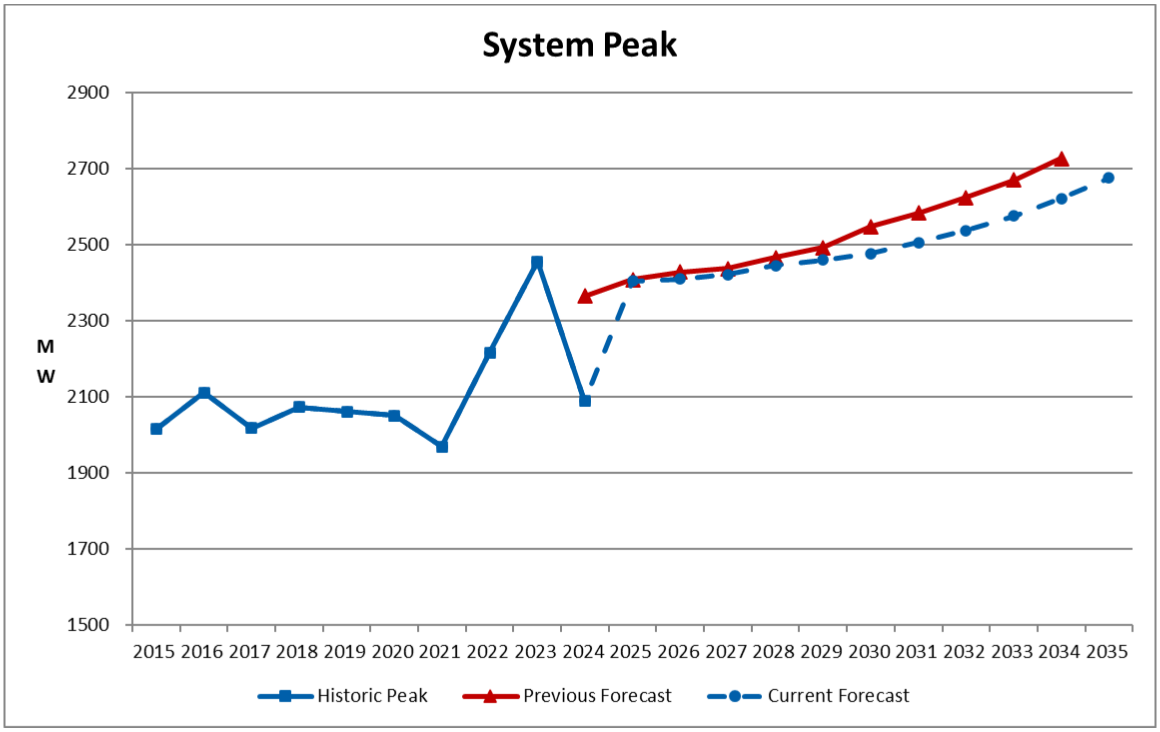
For the 2025 Load Forecast, as discussed in **Section 4.2,** the assumed peak temperature inputs use a lagging 12-hour average as well as windspeed. The coefficients used for peak normalization are the same as those used in the 2024 forecast and are described in **Figure 61** below:

Figure 61: Peak Regression Coefficients

Coefficient	Value	Description
Weekdays	30.5	Peaks that occur on weekdays will be 30.5MW higher than those on weekends, all else being equal.
Wind	2.7	Average daily windspeed will add 2.7MW for every 1km/hr. 10 year average is 18.8 km/hr on peak days.
12hrAvgLag	-28.0	12 hour lagging average of temperature, for a drop of 1 degree Celsius the peak will increase 28MW.

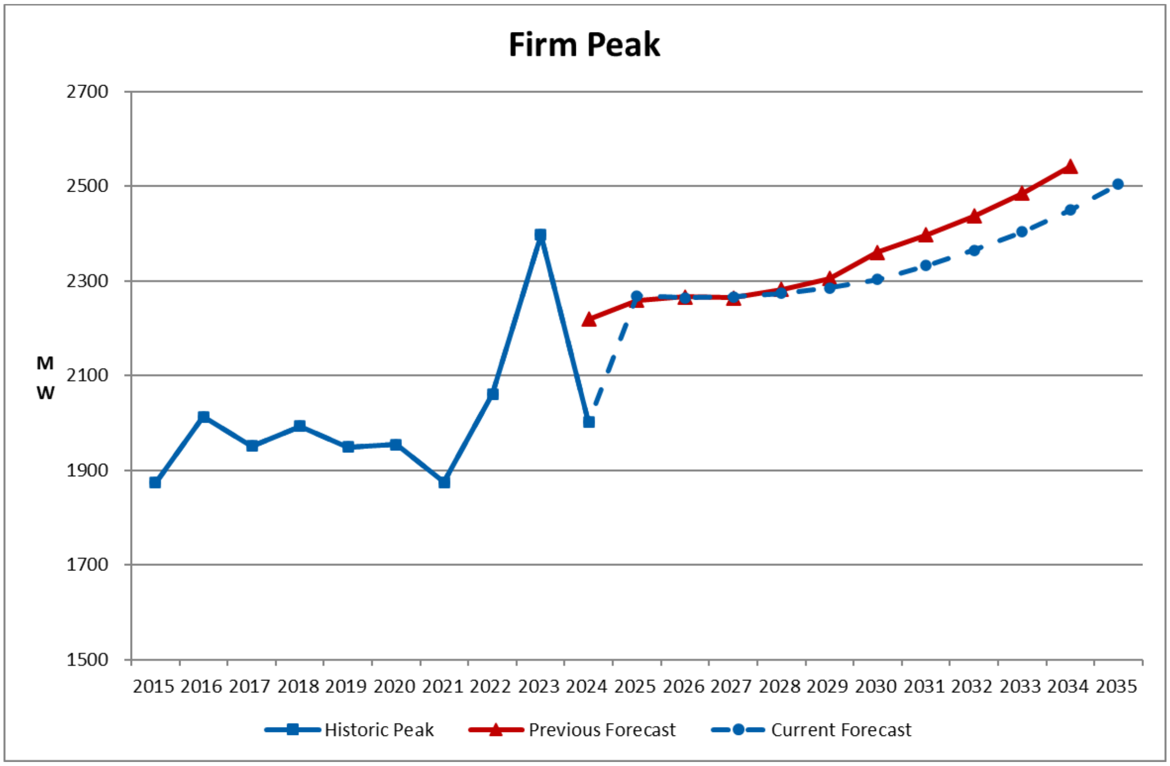
The peak contribution from large customer classes continues to be calculated from historical coincident load factors for each of the rate classes, and the large customer forecast is added to the accrued class forecast to obtain the total system peak. The forecast system peak for 2025 to 2035 is shown below in **Figure 62**, and is expected to increase by 1.2 percent annually. The peak is similar to the 2024 forecast in the near term and is lower in the longer term due to reduced EV peak impact.

Figure 62: Historical and Forecast System Peak (no DR)



As indicated in **Figure 63**, the firm peak (system peak less interruptible and DR) is expected to increase by 1.1 percent annually.

Figure 63: Historical and Forecast Firm Peak (including DR)



Forecast peak values, firm peak and interruptible peak information can be found in **Appendix A**.

Normalizing the firm peak for temperature, wind and weekday/weekend (and for lighting load in 2019, 2023 and 2024), the historic trend shows a better fit with the forecast peaks as shown in **Figure 64**.

Figure 64: Weather-Normalized Firm Peak (including DR)

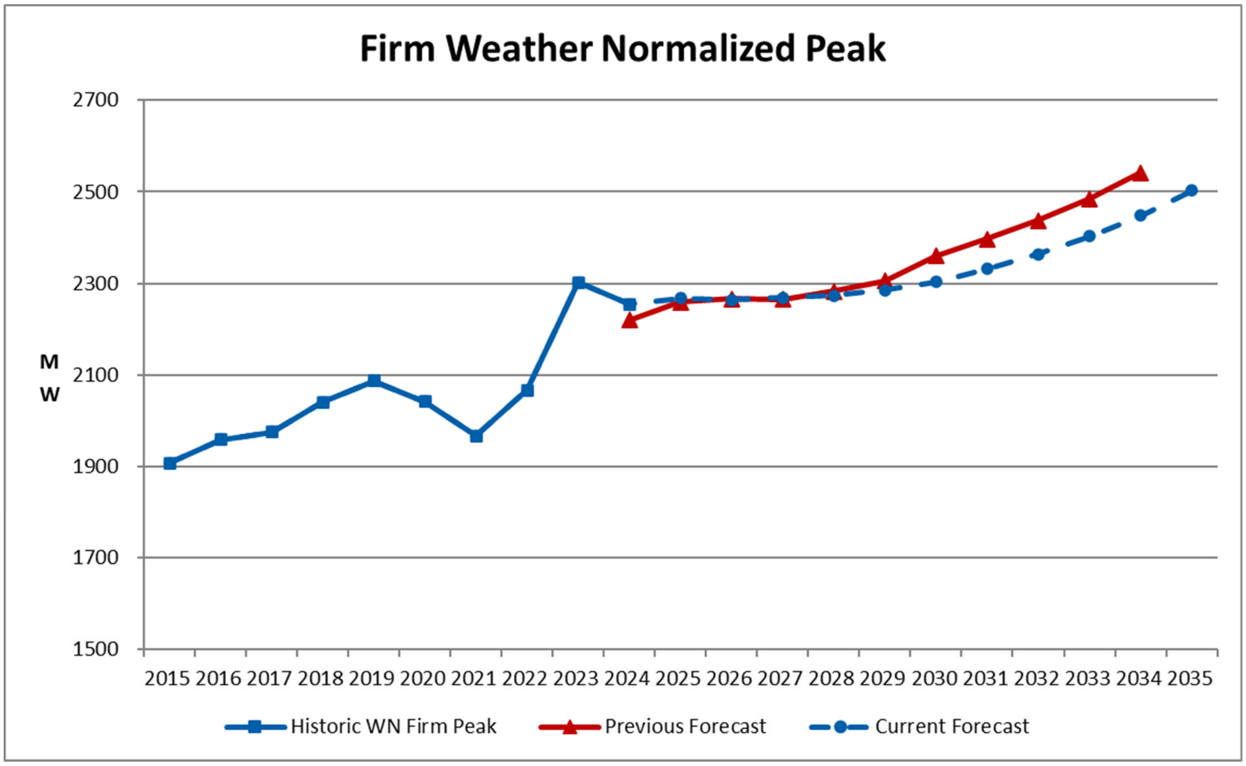


Figure 65 below shows the breakdown of the peak forecast by the various components.

Figure 65: Peak Contribution Components (MW)

	Modeled Peak (MW)	Res Heat (MW)	EV (MW)	DR (MW)	Hybrid (MW)	C&I Elect. (MW)	Large Cust. (MW)	DSM (MW)	Firm Peak (MW)	Inter. Cust. (MW)	System Peak (MW)
2025	2,180	2	3	-4	-	0	96	-11	2267	132	2,403
2035	2,455	17	121	-37	-48	4	105	-114	2502	132	2,672
2035 (max non-coincident EV peak)	2,455	17	178	-37	-48	4	105	-114	2559	132	2,729

Modeled peak is the end-use forecast portion that represents the peak contribution of the Residential, Small and General Demand, Small and Medium Industrial classes, as well as losses.

contributions, and finally DSM. As discussed in **Section 4.4**, the EV contribution to peak is expected to be partially mitigated via utility managed charging. The firm peak assuming the current non-coincident residential EV peak value of 0.5kW/vehicle and that commercial charging does not include peak mitigation (total average of 1.2 kW/ vehicle) would grow at 1.2 percent per year, and the overall impact in 2035 would be to add approximately 60 MW to the peak compared to the base assumptions. The space heating contribution to peak based on E3's hybrid modeling (as discussed in **Section 4.4**) is also included and is estimated to reduce peak by around 46 MW in 2035.

10.1 Analysis of 2024 Actual Peak

The 2024 system peak occurred at hour ending 8am on Wednesday, February 21, with a 12-hour lagging average temperature of -10.8°C and a daily average windspeed of 7.4 km/h. The recorded peak was 2,088 MW with a firm peak of 2,001 MW. **Figure 66** provides a breakdown of actual system peak compared to the forecast for 2024.

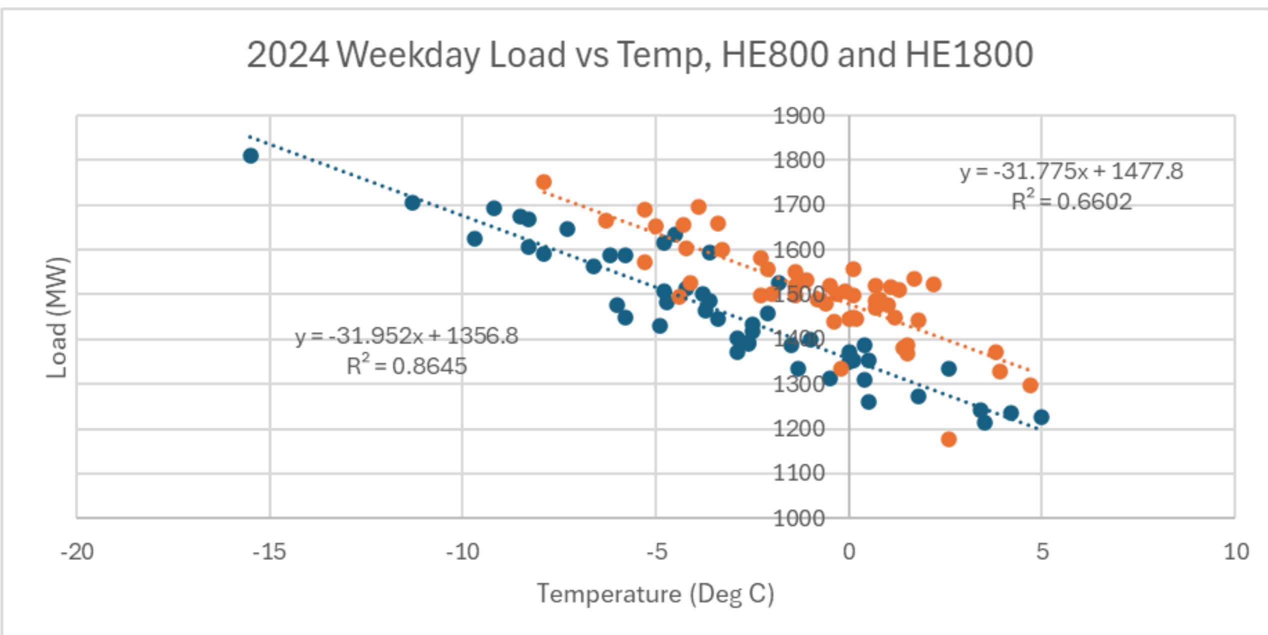
Figure 66: Forecast Peak Variance vs Actuals

	MW
2024 Forecast Peak	**2,365**
Interruptible	-57
Weather (-10.8°C 12hr lag avg)	-101
Wind (7.4 km/h daily avg)	-31
Morning peak impact (estimated)	-121
Unexplained	+33
2024 Actual Peak	**2,088**

The interruptible load variance of -57 MW represents the difference between forecasted peak load associated with the interruptible customers (144 MW in the 2024 forecast) compared with their actual load at the time of system peak (87 MW). The variance is largely the result of [redacted] related to the ELIADC load, which was reduced in response to planned dispatch requirements. The remainder (-7MW) is related to variance within the underlying interruptible customers compared to their forecast peak load. Note that it is the firm peak that is used for planning purposes, which excludes the interruptible load.

The impact of a morning vs evening peak, mostly related to lighting load that would be higher in the evening, is estimated by comparing load vs temperature series for 8am (the time of peak) and for 6pm (the time of peak in the forecast) for 2024 load data from Jan, Feb and Dec. Adding a linear trend line for each data series shows the underlying shift of approximately 121 MW (as shown by the difference in the intercepts of the equations) between a morning and an evening peak given similar temperatures. The details of the differences are not evident from this analysis, but all else being equal a morning peak would be expected to be lower than a temperature-equivalent evening peak by around 121 MW. The two series are shown in **Figure 67**.

Figure 67: Morning vs Evening Peak Difference



10.2 Solar Impact to Peak

The estimate for solar production at system peak demand was updated for 2025 based on an average of the factors used in the 2024 forecast and recalculated averages based on 2024 data. Hourly data from six community solar farms of varying size (10 kW to 67 kW) was compared to system hourly data to determine the coincidence factor (percentage of nameplate capacity at system peak time) on a monthly basis. As previously assumed, the coincidence factor in the winter months was 0 as the system peaks occurred in the evening. In the summer months, the average coincidence factor varies from 24 percent in September to 31 percent in August. The factors by month are provided in **Figure 68**. As these are impacted by both weather patterns affecting solar production (cloud cover) as well as the timing of the system peak, both of which can vary independently from year to year, the coincident factors will have to be monitored and updated in future forecasts. Since the annual system peak forecast is assumed to occur on a cold January evening after sunset, the coincidence factor impacting the maximum demand is unlikely to change in the near term.

Figure 68: Peak Contribution Components (MW)

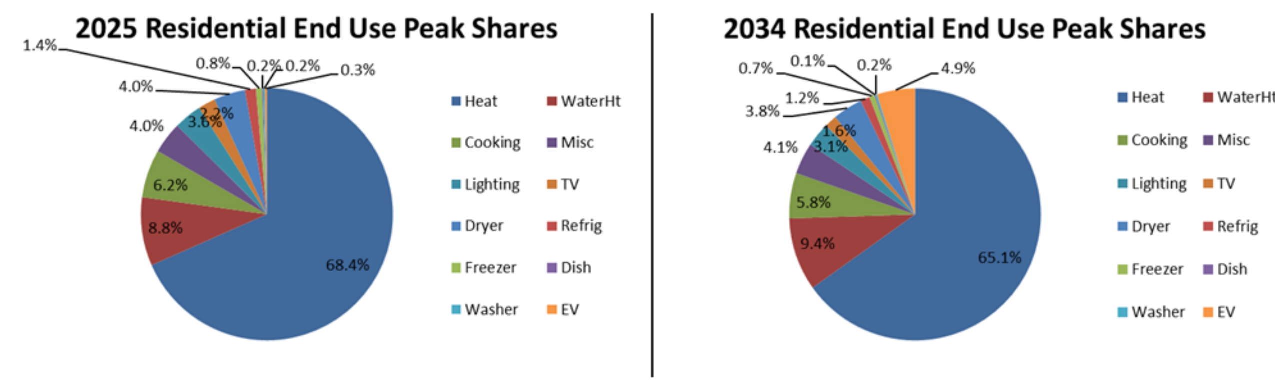
	Previous Coincident Factor (percent)	2024 Coincidence Factor (percent)	Average Coincidence Factor (percent)
January	0	0	0
February	0	1	0
March	1	2	2
April	1	3	2
May	10	24	17
June	21	35	28
July	35	20	27
August	33	28	31
September	39	9	24
October	5	6	5
November	0	0	0
December	0	0	0

10.3 End Use Peak Estimates

While the Load Forecast is a good statistical fit for the historical data, it presents challenges when trying to assess the contribution of individual end uses to peak by class. The overall peak forecast looks at the heating, cooling, and other variables across the Residential and Commercial classes. To illustrate the impact of the individual end uses on the peak for the individual classes, the coincident peak contribution of each class (Residential, Commercial and Industrial) is derived from load research data and fit to the energy amounts from the end-use models. The individual end-use shapes are then fit to the end-use intensity energy amounts from the end-use models.

Figure 69 below shows illustrative breakdowns of contribution to peak by Residential end use.

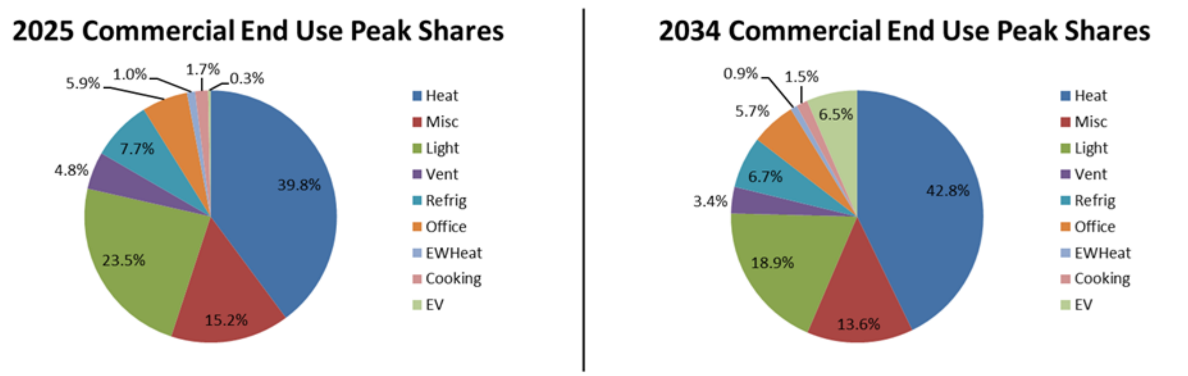
Figure 69: Residential End-Use Peak Shares



Over the forecast period, the greatest changes in relative contribution to peak are in EVs, increasing from 0.3 percent in 2025 to 4.9 percent by 2034, and electric heating sources, decreasing from 68.4 percent in 2025 to 65.1 percent in 2035. The contribution from all other end uses remains stable by comparison, fluctuating by at most ± 0.6 percent.

Figure 70 shows the breakdown in the contribution to peak by Commercial end use.

Figure 70: Commercial End-Use Peak Shares



As with the residential class, there is a significant increase in peak contribution from EVs, increasing from 0.3 percent in 2025 to 6.2 percent in 2034. The electrification of space heating in the commercial sector also drives an increase in the relative contribution to peak from electric heating sources, growing from 39.8 percent in 2025 to 42.8 percent in 2034. All other end uses see a decline in relative peak contribution, with the greatest drop in lighting which decreases from 23.5 percent in 2025 to 18.9 percent in 2034.

10.4 Current Class Coincident Peak Demand Research

NS Power has been exploring ways of using interval data to understand peak at the class level from a bottom-up perspective, as discussed in prior Load Forecast reports. NS Power currently forecasts system peak at the aggregate level, as it is the most complete and granular information available (provided by the generation stations). Once peak information is obtained, the system peak is disaggregated into rate class contributions based on historic load factors, losses, and load research data. Like the 2024 forecast, for 2025 the class load data used AMI interval data, with a more complete data set than in 2023.

Figures 71 and **72** show the 2024 combined AMI data for each customer class. The "rest" category is the sum of all the fully sampled (100 percent) classes, including Large Industrial customers. To create these figures, the sum of all the available AMI meters, per hour, per class, is later adjusted so the monthly totals correspond to revenue class sales information. **Figure 71** shows how having an improved hourly resolution due to AMI makes the sum of all customer classes follow generation with greater accuracy and smoothness (the gap is system energy losses). In contrast, in previous years, similar plots would exhibit sharp edges that reflect the statistical uncertainty of the LRS information, increasingly degrading year after year.

Figure 71: 2024 AMI class load shapes vs System Generation, 2024 Annual Peak

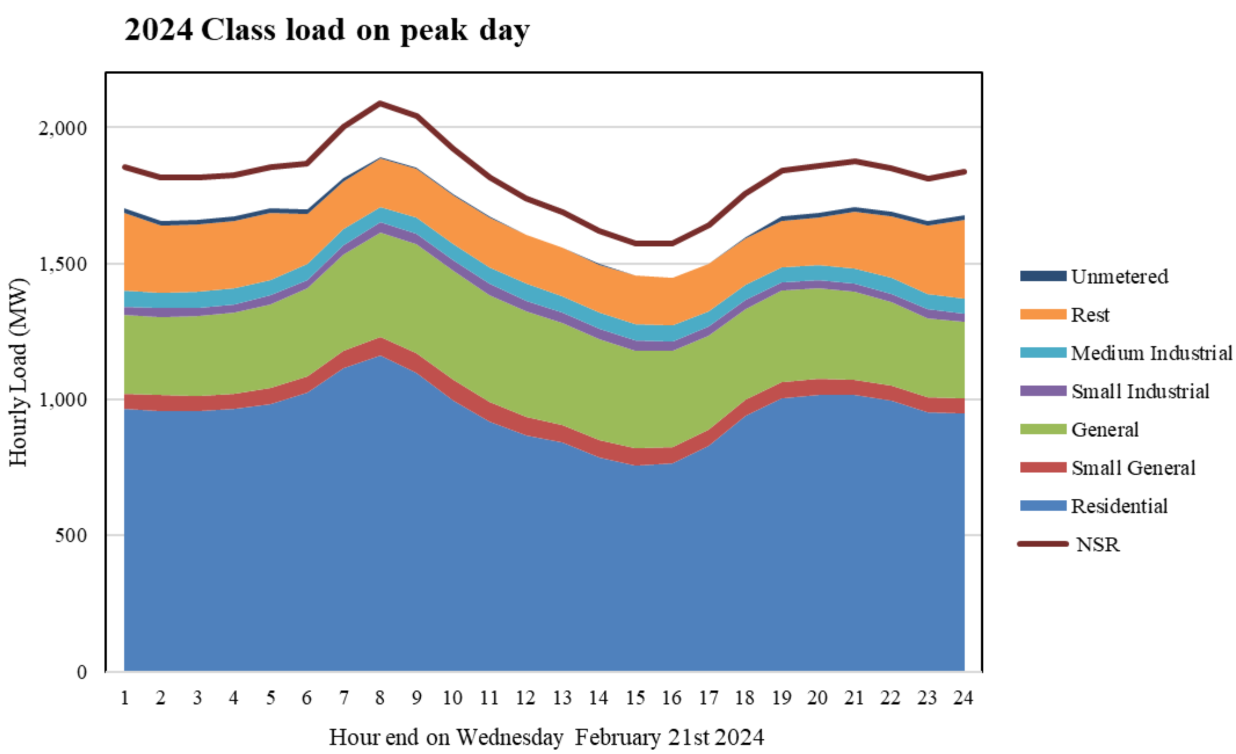
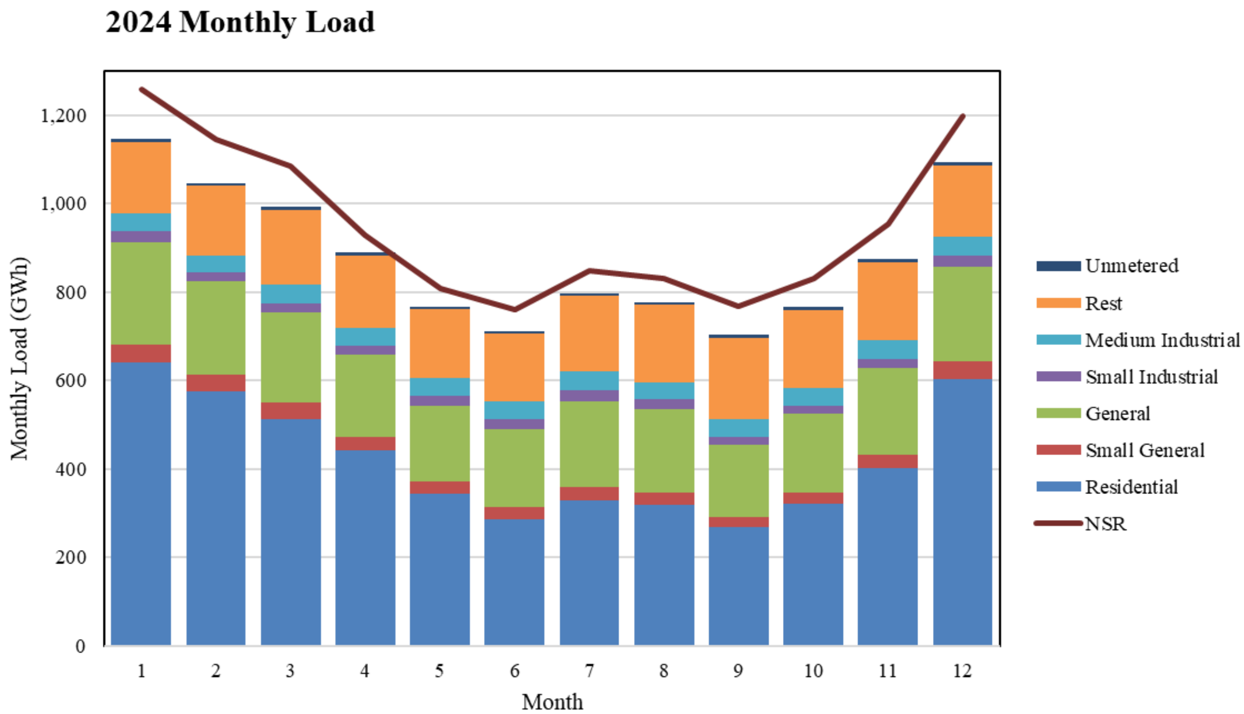


Figure 72: 2024 Monthly class sums from AMI data vs System Generation



10.5 AMI Data Used in the 2025 Forecast

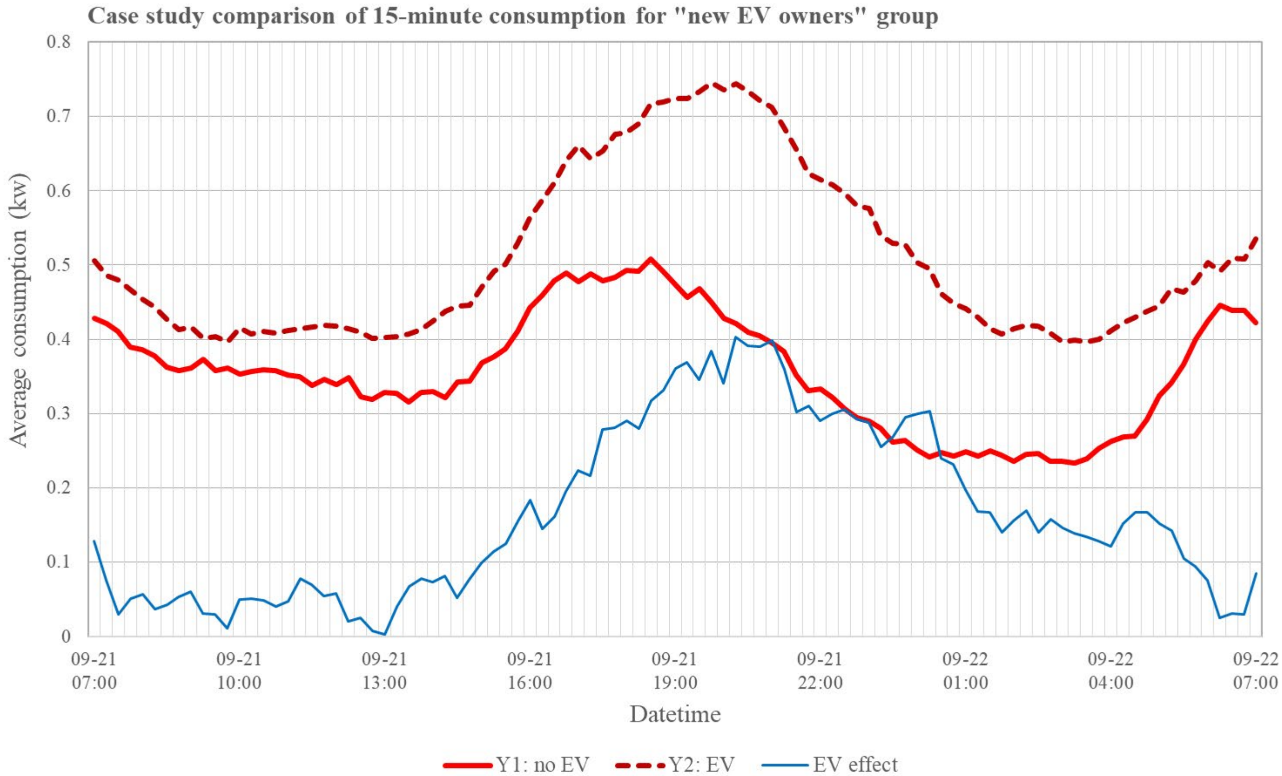
AMI data was used to create class-level load shapes for 2024, offering a more complete picture of customer consumption patterns than previously allowed using the Load Research Sample (LRS) method. Work in 2024 focused on ensuring that the interval data being used properly reflects the corresponding class level consumption and developing methods and procedures for future years, including data quality checks during the process of hourly aggregation.

There are two specific examples documented in this report where AMI data directly led to improvements in the Load Forecast: analyzing the impact of EVs on residential sales and peak (as described in **Section 4.4.3**); and the analysis of consumption differences between new single-family units and dwellings within multi-unit residential buildings (as described in **Section 5.0**). In the case of EVs, analysis benefited from the high frequency of interval reads and the large sample of customers available for analysis, operating their vehicles in Nova Scotia. This contrasts with previous model assumptions, which relied on insights from the limited sample in the Smart

Grid NS project, or data obtained from other regions of the world where driving characteristics and public charging infrastructure may differ compared to Nova Scotia. **Figure 73** demonstrates the value of 15-minute interval data for the EV analysis, with the EV effect clearly peaking in the evening/overnight, consistent with expectation based on understanding of residential EV charging habits but only detectable with this granularity of data. In the case of SFU and MURB consumption, analysis again benefited from the large sample size, capturing a broad range of customer usage for both housing types. This analysis also demonstrated the value of AMI integration with other datasets, with the SFU/MURB segmentation utilizing information on street address and incorporating data from external sources such as the Property Valuation Service Corporation (PVSC) for building age. For both cases and in future research, the AMI infrastructure and analysis capability being developed allow for reproducibility, ensuring that data insights and model parameters remain current and relevant.

Going forward, AMI data will be investigated for assessment of the impact of changing end-use stocks on class- and system-level load shapes, for example quantifying sensitivity of the residential peak magnitude and timing with the presence of electric heating. Research targeted at specific end uses may also allow for potential refinements of saturation and intensity values used in the forecasting SAE models.

1 **Figure 73: Example of time-varying EV effect detection in AMI data**



2

11.0 SENSITIVITY ANALYSIS

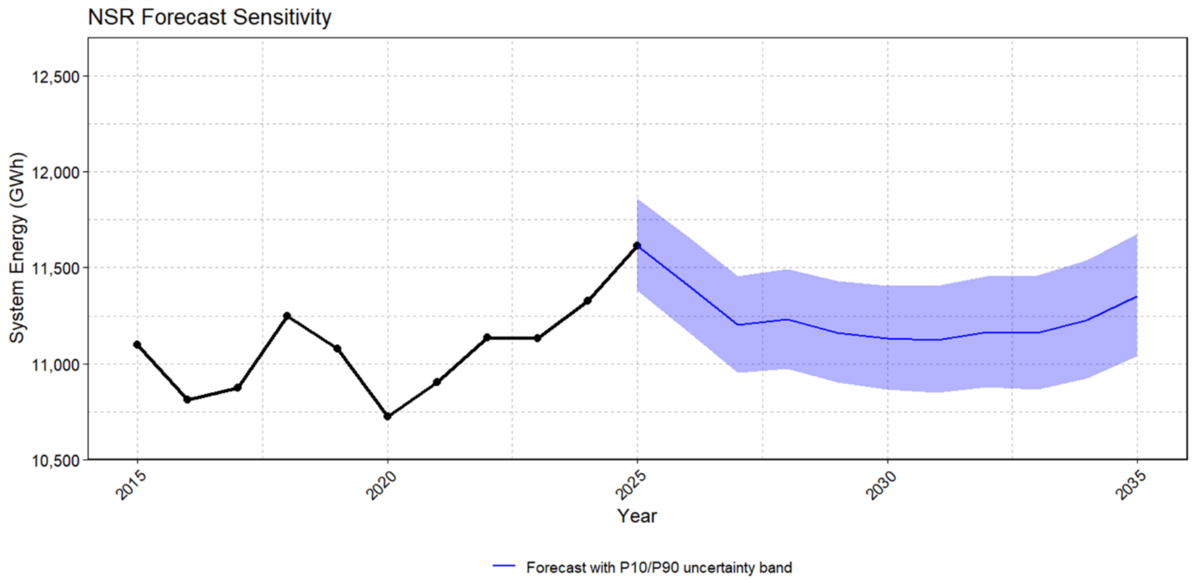
The sales and peak forecasts are fundamentally uncertain and depend on many variables, including economics, weather, adoption of distributed generation, electricity rates and DSM. Although each of these variables is forecast discretely, the uncertainty in these data sets will impact the load forecast to varying degrees. Load can also be affected by extraordinary events such as economic events, strikes, trade disputes, natural disasters, pandemics, and volatility in commodities.

In 2017, based on recommendations from Synapse on the 2016 Load Forecast, NS Power developed a P10/P90 probability analysis using the Monte Carlo simulation approach. This was to create a high and low range for the forecast that encompasses possible (not extreme) scenarios. A full description of the sensitivity methodology is contained in Appendix D.

The probable distribution of future load is estimated by sampling 10,000 random trial values of the economics and weather each year, using their respective historical distributions.

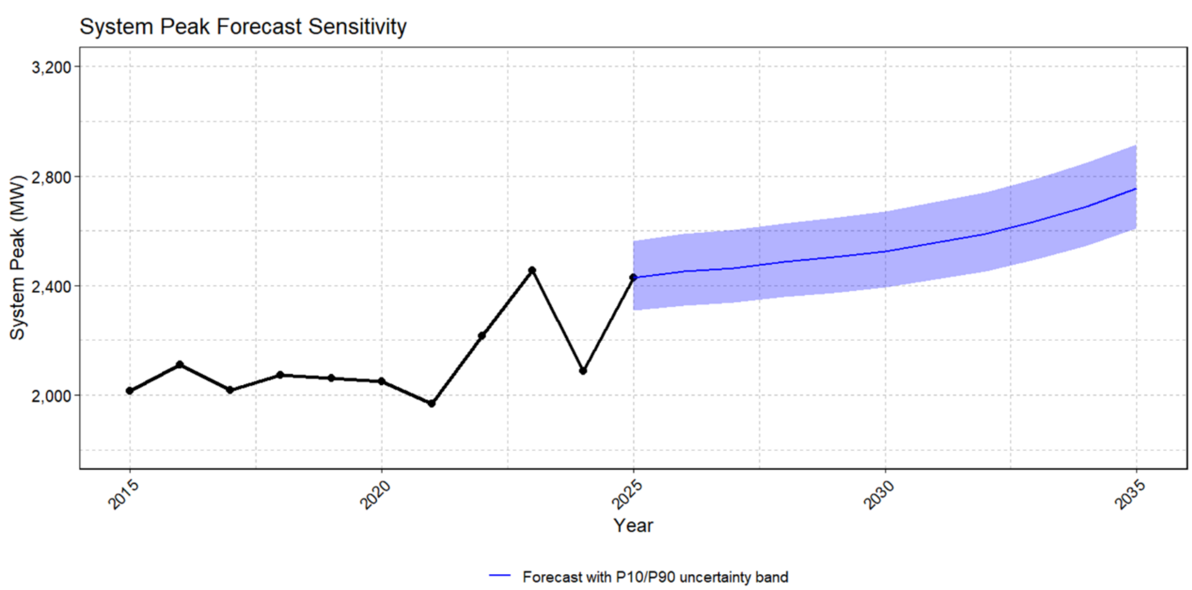
Figure 74 shows the sensitivity bands, which are represented by the shaded regions. These represent a range from the low 10th percentile to the high 90th percentiles (there is a 10/90 percent probability that the forecast will be below/above these shaded areas). These P10/P90 bands cover a range of approximately 480-636 GWh during the 10-year period, which is explained mainly by the impact of weather variation (HDD) and economic impact in the long term. The black line and points represent actual system totals.

Figure 74: System Energy Sensitivity



Similarly, a P10/P90 scenario was created for peak demand using a random sampling of weather and economic drivers. The width of the P10/P90 envelope is approximately 256 – 306 MW, reflecting the greater overall variation in the peak. **Figure 75** shows the peak forecast, which includes the latest adjustments (wind and 12-hour temperature averages) to the peak end-use model.

Figure 75: System Peak Sensitivity



This analysis provides a potential range of outcomes for the 2025 Load Forecast. Energy is most sensitive to economics over the long term, while peak is most sensitive to temperature. In addition, peak is more variable overall. The impacts of other inputs that cannot easily be represented by probabilistic analysis are provided in **Figure D8** in **Appendix D**.

11.1 Evergreen IRP Comparison

Figure 76 below compares the 2024 Load Forecast, the 2025 Load Forecast, and the Company's Evergreen IRP cases with Base DSM. The Evergreen IRP analysis incorporated the 2022 Load Forecast as its central planning case, which had a much lower estimate for load served through the RTR market (29 GWh compared to 421 GWh in the present forecast), as well as lower initial peak expectations. There are no specific assumptions around incentives that might impact EV and heat pump uptake; the values represent a slow ramp-up of uptake of these technologies that would allow interim sales targets as well as the target of net zero emissions by 2050 to be achieved. There will be more policy and regulation changes related to decarbonization targets in the course of the 10-year timeframe of this forecast, but the scenario developed represents the likely trajectories of these technologies.

Figure 76: 2022 Evergreen IRP Scenarios Comparison

Item	2025 NSR Energy (GWh)	2025 Firm Peak (MW)	2035 NSR Energy (GWh)	2035 Firm Peak (MW)
2024 Load Forecast	11,408	2,259	11,842	2,609
2025 Load Forecast	11,607	2,267	11,365	2,503
Evergreen IRP E1 – Current Policy and Trends	11,258	2,074	11,919	2,531
Evergreen IRP E2 – Hybrid Peak Mitigation	11,213	2,001	11,809	2,423
Evergreen IRP E3 – Accelerated Electrification	11,258	2,074	12,711	2,950

Appendix A – Forecast Values

2025 NS Power Load Forecast

Appendix A – Forecast Values

1.1 Table A1: Energy Requirement – 2025 NS Power Forecast Energy Forecast

Year	Residential Sector	Growth	Commercial Sector	Growth	Industrial Sector	Growth	Municipal and Other	Growth	Losses	Total Energy	Growth
	GWh	%	GWh	%	GWh	%	GWh	%	GWh	GWh	%
2015	4,504	2.3	3,251	0.9	2,456	-2.6	197	-0.2	691	11,099	0.6
2016	4,264	-5.3	3,133	-3.7	2,444	-0.5	179	-9.2	789	10,809	-2.6
2017	4,363	2.3	3,133	0.0	2,461	0.7	163	-9.0	753	10,873	0.6
2018	4,542	4.1	3,181	1.5	2,614	6.2	154	-5.7	758	11,250	3.5
2019	4,688	3.2	3,151	-0.9	2,388	-8.7	146	-4.7	704	11,077	-1.5
2020	4,675	-0.3	2,957	-6.2	2,343	-1.9	68	-53.6	688	10,731	-3.1
2021	4,619	-1.2%	2,973	0.7%	2,480	6.0%	72	5.6%	757	10,902	1.7%
2022	4,851	5.0%	3,088	3.9%	2,480	0.0%	69	-3.5%	645	11,134	2.1%
2023	4,934	1.7%	3,110	0.7%	2,161	-12.9%	154	122.5%	772	11,131	0.0%
2024	5,064	2.6%	3,129	0.6%	2,216	2.5%	144	-6.2%	773	11,326	1.8%
2025	5,289	4.4%	3,135	0.2%	2,258	1.9%	148	2.8%	777	11,607	2.5%
2026	5,246	-0.8%	3,067	-2.2%	2,213	-2.0%	113	-24.2%	764	11,403	-1.8%
2027	5,159	-1.7%	2,937	-4.2%	2,151	-2.8%	202	79.7%	743	11,193	-1.8%
2028	5,170	0.2%	2,934	-0.1%	2,176	1.1%	202	-0.1%	745	11,226	0.3%
2029	5,125	-0.9%	2,915	-0.6%	2,178	0.1%	202	-0.1%	739	11,159	-0.6%
2030	5,098	-0.5%	2,913	-0.1%	2,179	0.1%	202	0.0%	737	11,130	-0.3%
2031	5,090	-0.2%	2,915	0.1%	2,181	0.1%	202	0.1%	736	11,125	0.0%
2032	5,111	0.4%	2,933	0.6%	2,183	0.1%	203	0.2%	740	11,169	0.4%
2033	5,098	-0.3%	2,942	0.3%	2,186	0.1%	203	0.1%	740	11,168	0.0%
2034	5,131	0.7%	2,970	0.9%	2,187	0.1%	203	0.1%	745	11,236	0.6%
2035	5,205	1.4%	3,014	1.5%	2,187	0.0%	203	0.1%	755	11,365	1.1%

Table A2: Coincident Peak Demand - 2025 NS Power Forecast Peak Forecast

Year	Interruptible Contribution to Peak (MW)	Demand Response (reduction in Firm Peak only, MW)	Firm Contribution to Peak (MW)	Net System Peak (MW)	Growth (%)	Temp at Peak (deg C)	12hr Lag Temp (deg C)	Notes
2015	141	-	1,874	2,015	-4.9	-12	-12	January 6 weekday evening
2016	98	-	2,013	2,111	4.8	-14	-15	December 16 weekday evening
2017	67	-	1,951	2,018	-4.4	-13	-13	December 28 weekday evening (between holidays)
2018	80	-	1,993	2,073	2.7	-12	-13	January 7 weekend evening
2019	111	-	1,949	2,060	-0.6	-15	-14	February 27 weekday morning (min lighting load)
2020	96	-	1,954	2,050	-0.5	-13	-10	January 17 weekday evening
2021	94	-	1,875	1,968	-4.0	-10	-10	March 2 weekday evening
2022	155	-	2,061	2,216	12.6	-15	-14	January 11 weekday evening
2023	58	-	2,397	2,455	10.8	-22	-23	February 4 weekend noon
2024	87	-	2,001	2,088	-14.9	-16	-11	February 21 weekday morning (min lighting load)
2025	132	4	2,267	2,403	15.1		-14	Forecast
2026	133	12	2,263	2,408	0.2		-14	Forecast
2027	131	24	2,268	2,423	0.6		-14	Forecast
2028	133	36	2,274	2,443	0.8		-14	Forecast
2029	134	39	2,285	2,458	0.6		-14	Forecast
2030	132	39	2,303	2,474	0.7		-14	Forecast
2031	132	39	2,332	2,503	1.2		-14	Forecast
2032	133	38	2,364	2,535	1.3		-13	Forecast
2033	133	38	2,402	2,573	1.5		-13	Forecast
2034	132	37	2,449	2,618	1.8		-13	Forecast
2035	132	37	2,503	2,672	2.0		-13	Forecast

Appendix B – Forecast Model Details

2025 NS Power Load Forecast

Residential Model Detail

The residential average use SAE model is defined as a function of the three primary end uses – cooling (*XCool*), heating (*XHeat*) and other use (*XOther*):

$$ResAvgUse_m = b_1 \times XHeat_m + b_2 \times XCool_m + b_3 \times XOther_m + b_4 \times AvgEESavings_m + b_5 \times CovidVariable_m + \sum Binaries + ARMA$$

The end-use variables incorporate both a variable that captures short-term utilization (Use) and a variable that captures changes in end-use efficiency and saturation trends (Index). The heating variable is calculated as:

$$XHeat = HeatUse \times HeatIndex$$

HeatUse is defined as:

$$HeatUse_{y,m} = \left(\frac{HDD_{y,m}}{HDD_{15}}\right) \times \left(\frac{HHSize_{y,m}}{HHSize_{15}}\right)^{HHSizeElas} \times \left(\frac{ResEcon_{y,m}}{ResEcon_{15}}\right)^{HHIncElas} \times \left(\frac{Price_{y,m}}{Price_{15}}\right)^{PriceElas}$$

Where $HDD_{y,m}$ is the Heating Degree Day for a given month *m* of the year *y*, *HHSize* is the average household size, *ResEcon* is Employment Compensation divided by House Hold population, *Price* is the price of electricity for the specific customer class. Each variable uses its own elasticity, and the base line year is 2015.

HeatIndex is defined as:

HeatIndex = f(Heating Saturation, Efficiency, Shell Integrity, Square Footage)

The cooling variable is defined as:

$$XCool = CoolUse \times CoolIndex$$

CoolUse is defined as:

$$CoolUse_{y,m} = \left(\frac{CDD_{y,m}}{CDD_{15}}\right) \times \left(\frac{HHSize_{y,m}}{HHSize_{15}}\right)^{HHSizeElas} \times \left(\frac{ResEcon_{y,m}}{ResEcon_{15}}\right)^{HHIncElas} \times \left(\frac{Price_{y,m}}{Price_{15}}\right)^{PriceElas}$$

Where $CDD_{y,m}$ is the Cooling Degree Day for a given month *m* of the year *y*, *HHSize* is the average household size, *ResEcon* is Employment Compensation divided by House Hold population, *Price* is the price of electricity for the specific customer class. Each variable uses its own elasticity, and the base line year is 2015.

CoolIndex is defined as:

CoolIndex = f(Cooling Saturation, Efficiency, Shell Integrity, Square Footage)

XOther captures non-weather sensitive end uses:

XOther = OtherUse × OtherIndex

Where

OtherUse = f(Seasonal Use Pattern, Household Income, Household Size, and Price)
OtherIndex = g(Other Appliance Saturation and Efficiency Trends)

OtherUse is calculated as

$$OtherUse_{y,m} = \left(\frac{CDays_{y,m}}{30.44}\right) \times \left(\frac{HHSize_{y,m}}{HHSize_{15}}\right)^{HHSizeElas} \times \left(\frac{ResEcon_{y,m}}{ResEcon_{15}}\right)^{HHIncElas} \times \left(\frac{Price_{y,m}}{Price_{15}}\right)^{PriceElas}$$

Where $CDays_{y,m}$ is the number of days for a given month *m* of the year *y*, *HHSize* is the average household size, *ResEcon* is Employment Compensation divided by House Hold population, *Price* is the price of electricity for the specific customer class. Each accompanied by its own elasticities. Base line year is 2015.

OtherIndex is defined as:

$$OtherIndex_{y,m} = \sum\nolimits_{Type} EI_{15}^{Type} \times \frac{\left(Sat_y^{Type} / Eff_y^{Type}\right)}{\left(Sat_{15}^{Type} / Eff_{15}^{Type}\right)} \times MoMult_m^{Type}$$

Where *Type* is an end-use, Sat_y^{Type} is the saturation (shares) of an end-use of given *Type* for a particular year *y*, Eff_y^{Type} is the efficiency of an end-use of given *Type* for a particular year *y*, and EI_{15}^{Type} is a reference year (2015) calibration weight per end-use *Type*. The factors:

$$EI_{15}^{Type} \times \frac{\left(Sat_y^{Type} / Eff_y^{Type}\right)}{\left(Sat_{15}^{Type} / Eff_{15}^{Type}\right)}$$

are the annual intensities in the Intensities tab in Attachment 1 - Residential Intensities of the Load Forecast Report for each relevant end-use and converted to monthly values using the $MoMult_m^{Type}$ factor.

The *AvgEESavings* term captures E1's DSM past reported savings for the residential class. The associated regression coefficient, b_4, assesses the portion of embedded DSM activity that is already included in the billed sales information. The negative sign of b_4 indicates that DSM activity reduces load.

The COVID variable is a binary that starts in July 2020 and attempts to mirror the impacts of COVID on load. It starts with a value of 1, is reduced to 0.01 by August 2023. As discussed in **Section 5**, this variable was used to explain the increase in residential load from people working from home during the pandemic and subsequent years, but is removed from the forecast period.

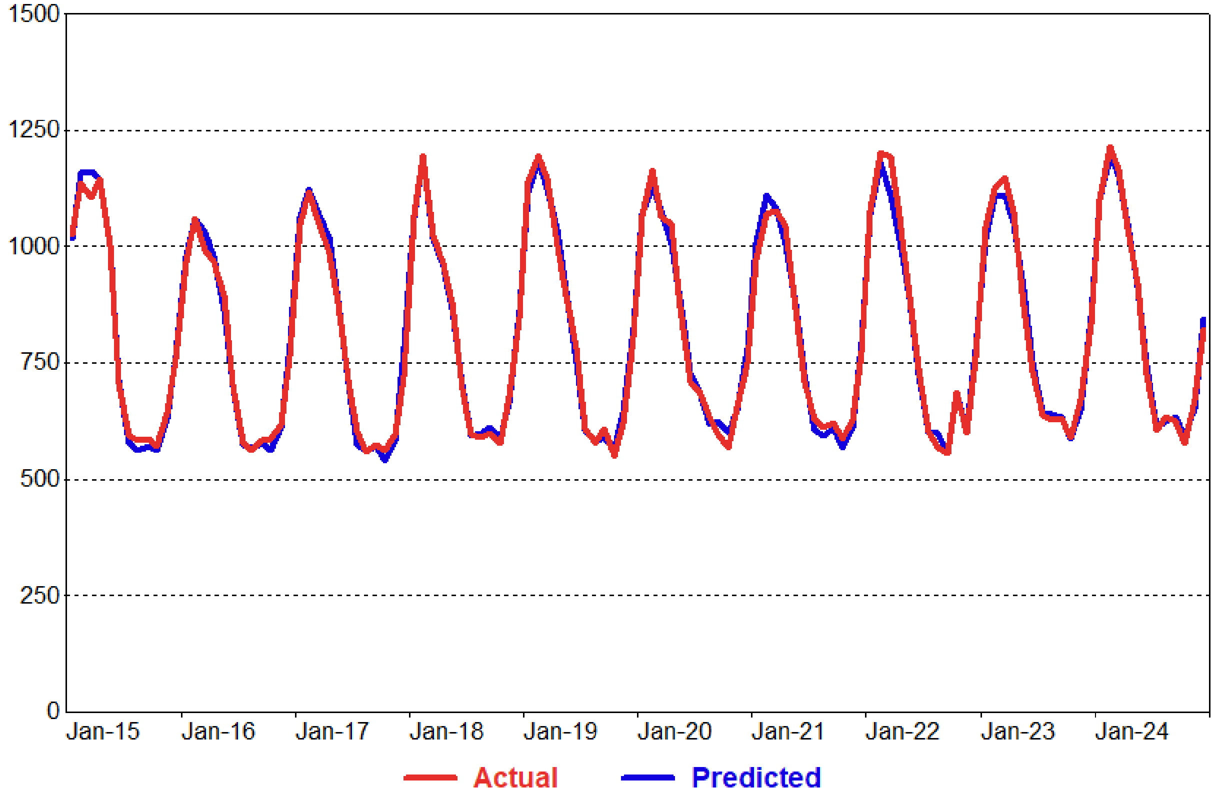
Binary shift variables are added to the model for the months of January, August, September, and October to improve model fit and particular monthly trends, while binaries for April and May of 2015 and September and October 2022 to compensate for anomalies in the billing data during these period related to delayed meter reads. Additional binaries were added for February 2018 and July 2020 to correct for high residual values. After running the linear regression with the main variables, the residuals show a slight autocorrelation, which happens when a model does not take into account relatively small drivers that should explain the dependent variable (in this case, sales).

Variable	Coefficient	StdErr	T-Stat	P-Value
MStructRes.WtXHeat	0.926	0.018	51.423	0.00%
MStructRes.WtXCool	1.147	0.185	6.205	0.00%
MStructRes.WtXOther	0.925	0.032	29.357	0.00%
MSales.AvgEESavingsProfiled	-0.414	0.161	-2.577	1.14%
MBin.Jan	64.155	8.126	7.895	0.00%
MBin.Aug	64.150	14.231	4.508	0.00%
MBin.Sep	87.298	15.740	5.546	0.00%
MBin.Oct	57.462	11.075	5.189	0.00%
MBin.Feb18	76.180	23.225	3.280	0.14%
MBin.May15	88.110	23.605	3.733	0.03%
MBin.Apr15	65.210	23.832	2.736	0.73%
MBin.Oct22	108.460	24.269	4.469	0.00%
MBin.Sep22	-70.147	24.590	-2.853	0.52%
MBin.Jul20	65.915	24.267	2.716	0.77%
MBin.Covid2020SteppedUpdate2	30.152	7.043	4.281	0.00%

Residential Model Statistics

Model Statistics	
Iterations	1
Adjusted Observations	120
Deg. of Freedom for Error	105
R-Squared	0.990
Adjusted R-Squared	0.989
AIC	6.375
BIC	6.723
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	-537.77
Model Sum of Squares	5,441,438.16
Sum of Squared Errors	54,852.50
Mean Squared Error	522.40
Std. Error of Regression	22.86
Mean Abs. Dev. (MAD)	16.40
Mean Abs. % Err. (MAPE)	2.05%
Durbin-Watson Statistic	1.592
Durbin-H Statistic	#NA
Ljung-Box Statistic	32.83
Prob (Ljung-Box)	0.1078
Skewness	0.227
Kurtosis	4.249
Jarque-Bera	8.828
Prob (Jarque-Bera)	0.0121

Residential SAE Model Fit



Residential Model 2025-2035 Reconciliation

The following tables provide details reflecting the changes between 2025 and 2035 forecast years. Some of the numbers have small discrepancies compared to those used in the final annual figures as there is a conversion between monthly data at the model level to annual data at the system level.

Residential Load – Post Regression (GWh)

	Existing Customer Average Use from Regression Model (kWh/year)	New Cust. Load	EVs	Solar	RTR	Hybrid	Res DSM Adjust ment	Res Sales		Total Res DSM (at the meter)	DSM captured by end uses
2025	10,475	62	11	(27)	-	-	(24)	5,289		(59)	(35)
2035	11,078	464	429	(650)	(117)	(202)	(291)	5,204		(703)	(412)
Change to load	5.8%	7.6%	7.9%	-11.7%	-2.2%	-3.8%	-5.0%	-1.6%			

Res Sales = Existing Customer + New Customer + EV + Solar + RTR + Hybrid + DSM

Existing customer load is calculated as Res Average Use (10,475 kWh/customer in 2025, 11,078 kWh/customer in 2035) x number of customers as of 2025 (502,855). The tables below show the appliance information incorporated in the end-use input tables.

Residential Average Use –Regression

	XHeat	XCool	XOther	AvgEE Savings	Binaries	ARMA	COVID Variable	Res Average Use
2025	4,977	492	5,199	(465)	273	-	-	10,475
2035	5,359	779	5,131	(465)	273	-	-	11,078
Change to load	3.7%	2.7%	-0.6%	0.0%	0.0%	0.0%	0.0%	5.8%

Res Avg Use = XHeat + XCool + XOther + AvgEESavings + Binaries + ARMA + COVID Var

Residential Input Variables – XHeat

	Intensities				Econ + Struct	Regression	
	Efurn	HP Heat	Secondary Heat	Furnace Fans	HeatUse Variable	Coeff	Total XHeat
2025	2,054	2,289	597	70	1.07	0.926	4,977
2035	1,042	3,945	767	60	1.00	0.926	5,359
Change to load	-20.3%	33.3%	3.4%	-0.2%	-7.2%	0.0%	7.7%

XHeat = (Efurn + HP Heat + Secondary Heat + Furnace Fans) x HeatUseVariable x Coeff

Note that because these factors are multiplicative, the growth rate for the intensities is multiplied by the coefficients to calculate the overall impact. For example, the contribution of Efurn is calculated as [($Efurn_{2035}$-$Efurn_{2025}$) x HeatUse x Coeff]/$WtXHeat_{2025}$

Residential Input Variables – XCool

	Intensities			Econ + Struct	Regression	
	Central AC	HP Cool	Room AC	CoolUse Variable	Coefficient	Total Xcool
2025	30	234	91	1.2	1.147	492
2035	35	358	137	1.3	1.147	779
Change to load	1.1%	25.2%	9.2%	6.1%	0.0%	58.4%

XCool = (Central AC + HP Cool + Room AC) x CoolUseVariable x Coeff

Residential Input Variables – XOther

	Intensities							Econ + Struct	Reg	
	Water Heat	Cook	Ref/Frz	Wash/ Dry	TV	Light	Misc	Other Use Var	Coeff	Total Xother
2025	1,674	475	556	718	402	507	1,195	1.02	0.925	5,199
2035	1,916	474	503	728	298	467	1,282	0.98	0.925	5,131
Change to load	4.7%	0.0%	-1.0%	0.2%	-2.0%	-0.8%	1.7%	-3.7%	0.0%	-1.3%

XOther = (Water Heat + Cook + Ref/Frz + Wash/Dry + TV + Light + Misc) x OtherUseVariable x Coeff

Commercial Model Detail

Small General Service

Small General Service is projected using an SAE average use model and a sales forecast is generated as the product of the average use and customer forecast.

Like the residential model, monthly Small General Service average use is defined as a function of monthly heating requirements (*XHeat*), cooling requirements (*XCool*), and other use (*XOther*). The end-use variables are constructed by interacting annual end-use intensity projections (EI) that capture end-use intensity trends, with *GDP* and employment ($SmlGenVar_m$), real price ($Price_m$), monthly *HDD* and *CDD* and a variable accounting for the number of days in a given month:

$$XHeat_m = EIheat \times Price_m^{-.15} \times SmlGenVar_m \times HDD_m$$

$$XCool_m = EIcool \times Price_m^{-.15} \times SmlGenVar_m \times CDD_m$$

$$XOther_m = EIother \times Price_m^{-.15} \times SmlGenVar_m \times Days_m$$

The coefficients on price are imposed short-term price elasticities. Several binary shift variables are added to the model to:

(1) Improve model fit using monthly binaries for March and December.
(2) Account for billing issues related to the pandemic in May and June 2020.
(3) Account for billing issues related to the hurricane Fiona in Oct 2022 and hurricane Lee in Sep 2023.
(4) Account for shifts in usage starting in 2024 (post COVID)

Analysis of the initial regression results indicated that the model would be improved by adding an ARMA process. A seasonal moving average of period 1, SMA(1) was used.

The monthly forecast average use sales model is then estimated as:

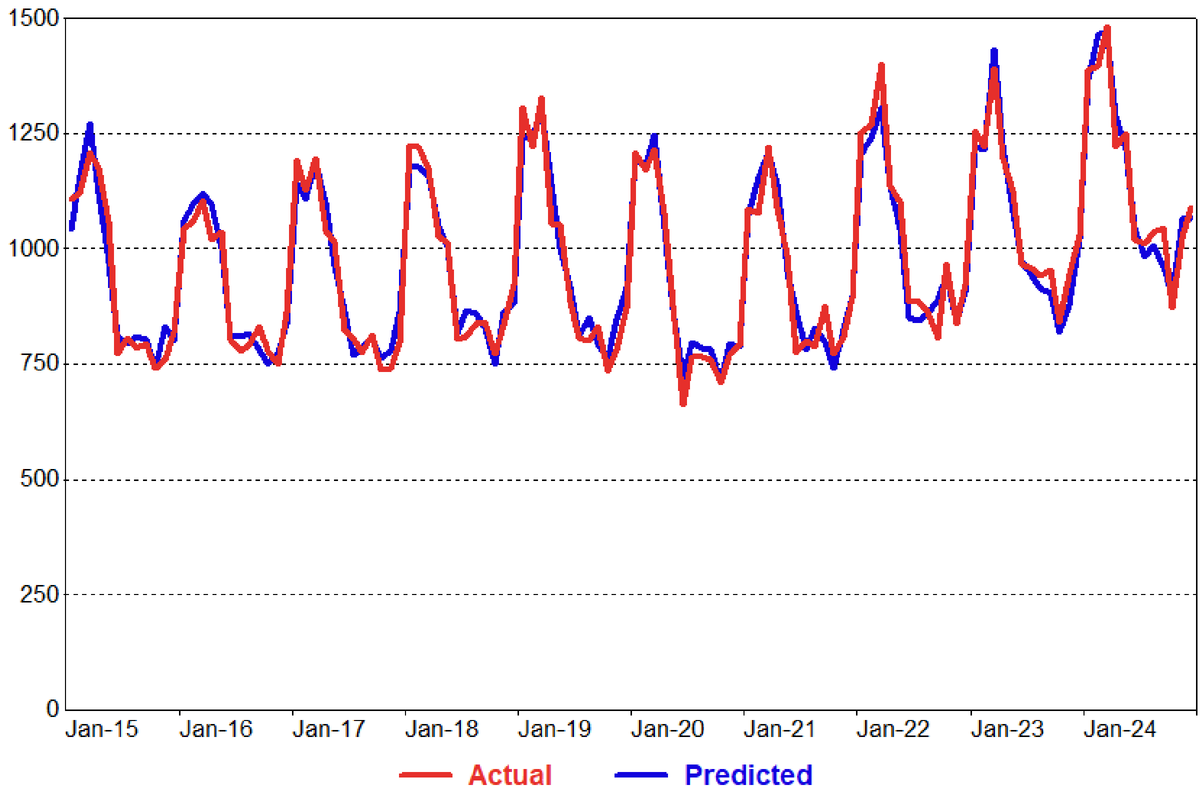
$$SmlGen\_AvgUse_m = b1 \times XHeat_m + b2 \times XCool_m + b3 \times XOther_m + \sum Binaries + ARMA$$

Variable	Coefficient	StdErr	T-Stat	P-Value
MStructSmlGen.WtXHeat	0.834	0.036	23.354	0.00%
MStructSmlGen.WtXCool	0.331	0.043	7.704	0.00%
MStructSmlGen.WtXOther	0.745	0.022	33.344	0.00%
MBin.Mar	100.517	23.139	4.344	0.00%
MBin.Dec	-121.561	21.777	-5.582	0.00%
MBin.May20	-141.284	35.708	-3.957	0.01%
MBin.Jun20	-126.958	35.334	-3.593	0.05%
MBin.Oct22	143.854	35.971	3.999	0.01%
MBin.Sep23	122.363	40.441	3.026	0.31%
MBin.Yr24Plus	107.731	13.270	8.118	0.00%
SMA(1)	0.578	0.089	6.484	0.00%

Small General Model Statistics

Model Statistics	
Iterations	14
Adjusted Observations	120
Deg. of Freedom for Error	109
R-Squared	0.954
Adjusted R-Squared	0.950
AIC	7.605
BIC	7.860
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	-615.56
Model Sum of Squares	4,157,886.22
Sum of Squared Errors	200,576.21
Mean Squared Error	1,840.15
Std. Error of Regression	42.90
Mean Abs. Dev. (MAD)	33.88
Mean Abs. % Err. (MAPE)	3.53%
Durbin-Watson Statistic	2.160
Durbin-H Statistic	#NA
Ljung-Box Statistic	49.56
Prob (Ljung-Box)	0.0016
Skewness	-0.074
Kurtosis	2.476
Jarque-Bera	1.481
Prob (Jarque-Bera)	0.4768

Small General Model Fit



Small General 2025-2035 Reconciliation

The Small General Demand customer forecast model is constructed like the residential model (including heat pump programs inside the SAE model). Adjustments done outside the regression include estimates for other commercial and industrial growth programs, PV, EV, RTR and DSM.

Historically the XHeat, XCool and XOther variables are constructed with a flat scaling factor to keep regression coefficients close to 1, which allows for easier comparison.

Small General Load – Post Regression (GWh)

	Load from Regression Model	EVs	Solar	RTR	SG DSM adjustment	Small Gen Sales (with DSM)		Total Res DSM (at the meter)	DSM captured by end uses
2025	378	2	(1)	-	(3)	374		(6)	(3)
2035	432	60	(26)	(3)	(24)	436		(56)	(32)
Change to load	14.3%	15.4%	-6.7%	-0.7%	-5.8%	16.6%			

Small General Sales = Avg Use Existing x customer count + EV Load + Solar Load + RTR + DSM

The load from the regression model is calculated as Small Gen Average Use (14,020 kWh/customer in 2025, 14,505 kWh/customer in 2035) x number of customers (26,981 in 2025, increasing to 29,804 in 2035).

Small General Average Use –Regression

	XHeat	XCool	XOther	Binaries	ARMA	Res Average Use
2025	4,449	623	7,676	1,272	-	14,020
2035	5,114	706	7,413	1,272	-	14,505
Change to load	4.7%	0.6%	-1.9%	0.0%	0.0%	3.5%

Small General Avg Use = XHeat + XCool + XOther + Binaries + ARMA

Small General Input Variables – XHeat

	Heating	HeatUse Variable	Coefficient	Scaling Factor	Total Xheat
2025	58,627	1.30	0.834	0.070	4,449
2035	65,869	1.33	0.834	0.070	5,114
Change to load	12.6%	2.3%	0.0%	0.0%	14.9%

XHeat = Heating x HeatUseVariable x Coeff x Scaling Factor

Note that because these factors are multiplicative, the growth rate for the intensities are multiplied by the coefficients to calculate the overall impact. For example, the contribution of

Heating is calculated as $[(Heat_{2035}-Heat_{2025}) \times HeatUse \times Coeff \times Scaling]/WtXHeat_{2025}$

Small General Input Variables – XCool

	Cooling	CoolUse Variable	Coefficient	Scaling Factor	Total Xcool
2025	36,586	1.47	0.331	0.035	623
2035	35,638	1.71	0.331	0.035	706
Change to load	-3.0%	16.3%	0.0%	0.0%	13.3%

XCool = Cooling x CoolUseVariable x Coeff x Scaling Factor

Small General Input Variables – XOther

	Intensities							Econ + Struct	Reg		
	Vent	Water Heat	Cook	Refrig	Light	Office	Misc	Other Use Var	Coeff	Scaling Factor	Total XOher
2025	11,716	1,979	1,911	20,884	56,126	13,236	32,909	14.85	0.745	0.005	7,676
2035	8,794	2,217	1,798	19,382	48,458	14,157	31,956	15.70	0.745	0.005	7,413
Change to load	-2.2%	0.2%	-0.1%	-1.1%	-5.8%	0.7%	-0.7%	5.7%	0.0%	0.0%	-3.4%

XOther = (Ventilation+ Water Heat + Cook + Refrigeration + Light + Office + Misc) x OtherUseVariable x Coeff x Scaling Factor

General Service

The General Service rate class model is estimated on a total monthly sales basis where total monthly billed sales is a function of total monthly heating requirements (*XHeat*), cooling requirements (*XCool*), and other use (*XOther*). The end-use variables are constructed by interacting annual end-use intensity projections (EI) that capture end-use intensity trends, with *GDP* and employment ($GenVar_m$), real price ($Price_m$), monthly *HDD* and *CDD* and a variable accounting for the number of days in a given month:

$XHeat_m = EIheat \times Price_m^{-.15} \times GenVar_m \times HDD_m$ $XCool_m = EIcool \times Price_m^{-.15} \times GenVar_m \times CDD_m$

$XOther_m = EIother \times Price_m^{-.15} \times GenVar_m \times Days_m$

The coefficients on price are imposed short-term price elasticities. Several binary shift variables are added to the model to:

(1) Improve model fit using monthly binaries for Feb 2018, June 2021 and Aug 2022.

(2) Account for billing issues related to the pandemic in April, May and June 2020.

(3) Account for billing issues related to the hurricane Fiona in Sep and Oct 2022.

(4) Account for shifts in usage starting in 2023 (post COVID)

As in the residential model, analysis of the initial regression results indicated that the model would be improved by adding an ARMA process. A seasonal moving average of period 1, SMA(1) was used.

A monthly forecast sales model is then estimated as:

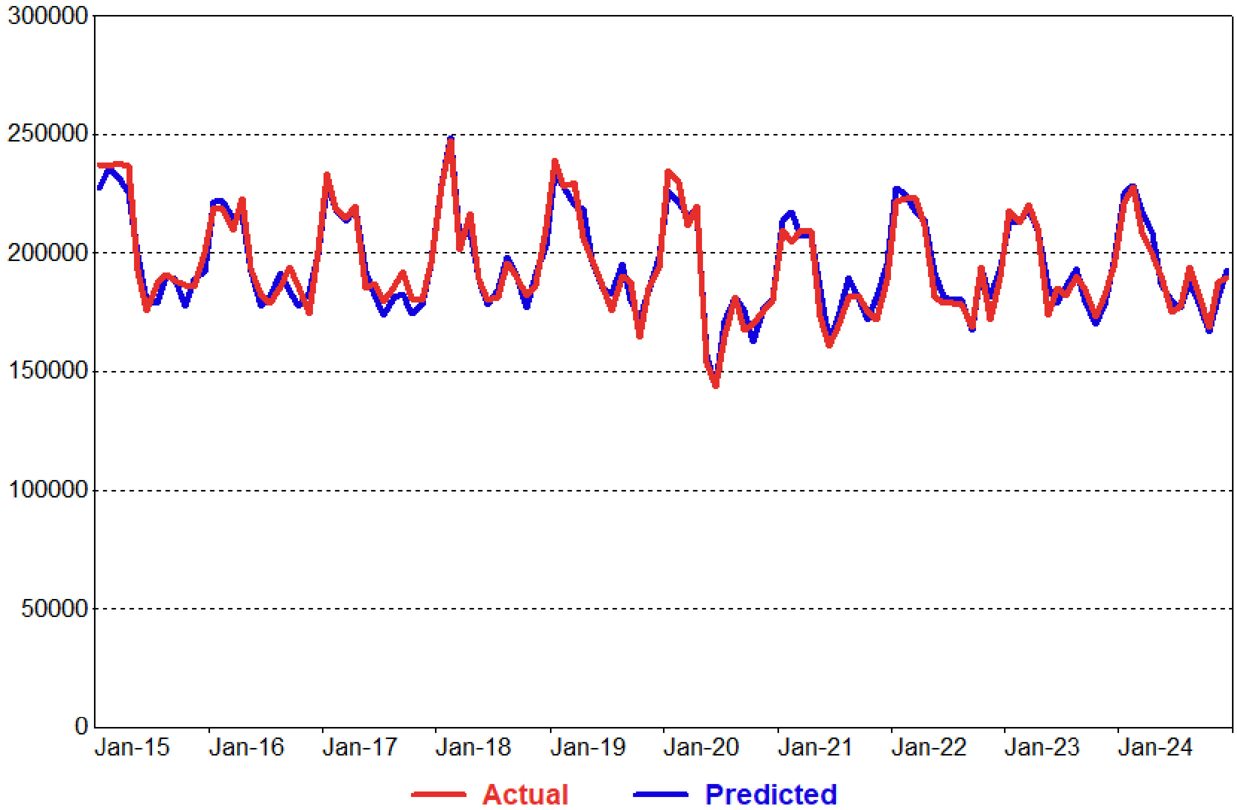
$GenService_m = b1 \times XHeat_m + b2 \times XCool_m + b3 \times XOther_m + \sum Binaries + ARMA$

Variable	Coefficient	StdErr	T-Stat	P-Value
MStructGen.WtXHeat	0.751	0.029	25.743	0.00%
MStructGen.WtXCool	0.719	0.059	12.200	0.00%
MStructGen.WtXOther	1.069	0.018	60.560	0.00%
MBin.Feb18	29617.613	5604.430	5.285	0.00%
MBin.May20	-32655.421	5591.939	-5.840	0.00%
MBin.Jun20	-32830.256	5921.870	-5.544	0.00%
MBin.Oct22	17728.676	5643.415	3.141	0.22%
MBin.Sep22	-23947.444	5704.061	-4.198	0.01%
MBin.Apr20	15546.563	5782.873	2.688	0.83%
MBin.Dec	-9625.022	2545.398	-3.781	0.03%
MBin.Yr23Plus	-8918.468	1593.773	-5.596	0.00%
MBin.Aug22	-17153.477	5808.763	-2.953	0.39%
MBin.Jun21	-18838.916	5915.501	-3.185	0.19%
SMA(1)	0.318	0.102	3.115	0.24%

General Service Model Statistics

Model Statistics	
Iterations	14
Adjusted Observations	120
Deg. of Freedom for Error	106
R-Squared	0.931
Adjusted R-Squared	0.923
AIC	17.467
BIC	17.793
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	-1,204.32
Model Sum of Squares	49,503,665,937.00
Sum of Squared Errors	3,663,043,315.60
Mean Squared Error	34,557,012.41
Std. Error of Regression	5,878.52
Mean Abs. Dev. (MAD)	4,477.60
Mean Abs. % Err. (MAPE)	2.32%
Durbin-Watson Statistic	2.068
Durbin-H Statistic	#NA
Ljung-Box Statistic	37.47
Prob (Ljung-Box)	0.0392
Skewness	-0.099
Kurtosis	2.417
Jarque-Bera	1.894
Prob (Jarque-Bera)	0.3879

General Service Model Fit



General Demand 2025-2035 Reconciliation

The general demand class, which makes up the largest portion of the commercial sector, is forecast as gross total sales rather than average use as is the case in the small general and residential classes.

Like the small general model, a flat scaling factor is used to adjust some of the end-use regression coefficients close to 1, making their interpretation a bit easier. Outside of the SAE regression model, adjustments include EV load, PV, RTR, Hybrid and DSM.

General Demand Load – Post Regression (GWh)

	Load from Regression Model	Model alignment	RTR	Hybrid Impact	EV	Solar	GD DSM Adjustment	Gen Sales (with DSM)		Total GD DSM (at the meter)	DSM captured by end uses
2025	2,359	(14)	-	-	7	(10)	(22)	2,320		(52)	(29)
2035	2,593	(14)	(165)	(85)	239	(237)	(181)	2,150		(418)	(237)
Change to load	10.0%	0.0%	-7.0%	-3.6%	9.9%	-9.7%	-6.8%	-7.3%			

Gen Sales = Sales + Model alignment (2024 actuals vs forecast) + RTR + EV Load + Solar Load + Hybrid + DSM

General Demand Sales –Regression

	XHeat	XCool	XOther	Binaries	ARMA	Sales (GWh)
2025	564,737	127,070	1,786,367	(116,647)	(2,279)	2,359,249
2035	749,648	151,266	1,808,747	(116,647)	-	2,593,014
Change to load	7.8%	1.0%	0.9%	0.0%	0.1%	9.9%

Sales = XHeat + XCool + XOther + Binaries + ARMA

General Demand Input Variables – WtXHeat

	Intensity	Econ + Structural	Regression		
	Heating	HeatUse Variable	Coefficient	Scaling Factor	Total Xheat
2025	560,995	1.34	0.751	564,737	560,995
2035	696,415	1.43	0.751	749,648	696,415
Change to load	25.8%	6.9%	0.0%	32.7%	25.8%

XHeat = Heating x HeatUseVariable x Coeff

Note that because these factors are multiplicative, the growth rate for the intensities are multiplied by the coefficients to calculate the overall impact. For example, the contribution of Heating is calculated as [($Heat_{2035}$-$Heat_{2025}$) x HeatUse x Coeff]/$WtXHeat_{2025}$

General Demand Input Variables – XCool

	Intensity	Econ + Structural	Regression		
	Cooling	CoolUse Variable	Coefficient	Scaling Factor	Total Xcool
2025	315,673	1.51	0.719	0.370	127,070
2035	307,496	1.85	0.719	0.370	151,266
Change to load	-3.2%	22.2%	0.0%	0.0%	19.0%

XCool = Cooling x CoolUseVariable x Coeff x Scaling Factor

General Demand Input Variables – XOther

	Intensities							Econ + Struct	Reg		
	Vent	Water Heat	Cook	Refrig	Light	Office	Misc	Other Use Var	Coeff	Scaling Factor	Total XOher
2025	108,261	14,274	17,656	192,984	456,715	122,313	304,107	15.27	1.069	0.090	1,786,367
2035	81,261	12,868	16,612	179,104	394,318	130,823	295,301	16.93	1.069	0.090	1,808,747
Change to load	-2.5%	-0.1%	-0.1%	-1.3%	-5.7%	0.8%	-0.8%	10.9%	0.0%	0.0%	1.3%

XOther = (Ventilation + Water Heat + Cooking + Refrigeration + Lighting + Office + Miscellaneous) x OtherUseVariable x Coeff x Scaling Factor

Industrial Econometric Model Details

Small Industrial model

$$SmlInd\_Sales_m = MBin.Jan_m + MBin.Feb_m + MBin.Mar_m + MBin.Apr_m + MBin.May_m + MBin.Jun_m + MBin.Jul_m + MBin.Aug_m + MBin.Sep_m + MBin.Oct_m + MBin.Nov_m + MBin.Dec_m + MBin.Oct22 + b1 \times MEcon.ManGDP$$

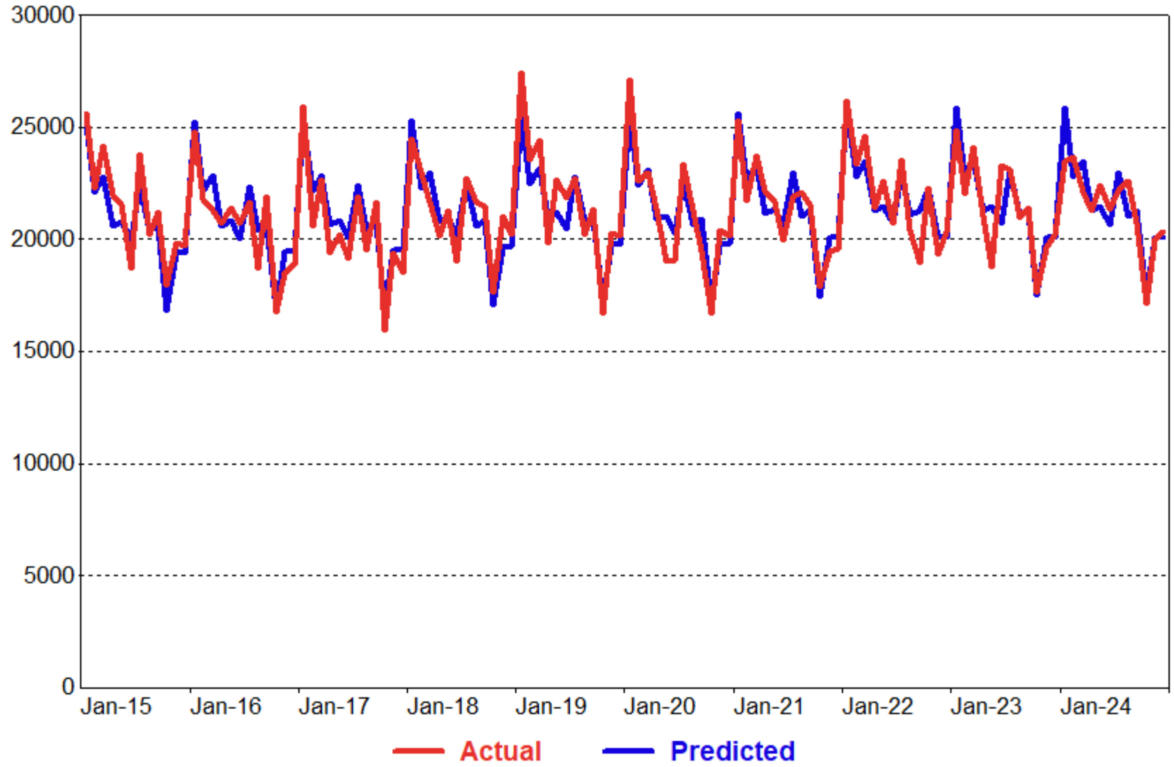
A binary variable was added for October 2022 to account for billing delays after hurricane Fiona.

Variable	Coefficient	StdErr	T-Stat	P-Value
MBin.Jan	21712.759	1366.359	15.891	0.00%
MBin.Feb	18642.698	1368.355	13.624	0.00%
MBin.Mar	19340.769	1370.352	14.114	0.00%
MBin.Apr	17112.610	1372.349	12.470	0.00%
MBin.May	17314.880	1374.346	12.599	0.00%
MBin.Jun	16539.837	1376.343	12.017	0.00%
MBin.Jul	18842.979	1378.340	13.671	0.00%
MBin.Aug	16913.441	1380.459	12.252	0.00%
MBin.Sep	17110.754	1382.579	12.376	0.00%
MBin.Oct	13321.337	1377.684	9.669	0.00%
MBin.Nov	15917.766	1386.819	11.478	0.00%
MBin.Dec	15930.495	1388.939	11.470	0.00%
MBin.Oct22	4830.446	1073.549	4.500	0.00%
MEcon.ManGDP	1.270	0.443	2.867	0.50%

Small Industrial Model Statistics

Model Statistics	
Iterations	1
Adjusted Observations	120
Deg. of Freedom for Error	106
R-Squared	0.812
Adjusted R-Squared	0.789
AIC	13.950
BIC	14.275
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	-993.27
Model Sum of Squares	469,004,375.16
Sum of Squared Errors	108,694,154.52
Mean Squared Error	1,025,416.55
Std. Error of Regression	1,012.63
Mean Abs. Dev. (MAD)	766.05
Mean Abs. % Err. (MAPE)	3.62%
Durbin-Watson Statistic	2.028
Durbin-H Statistic	#NA
Ljung-Box Statistic	35.95
Prob (Ljung-Box)	0.0555
Skewness	-0.274
Kurtosis	3.032
Jarque-Bera	1.510
Prob (Jarque-Bera)	0.4700

Small Industrial Model Fit



Medium Industrial Model

$MedInd\_Sales_m = MBin.Jan_m + MBin.Feb_m + MBin.Mar_m + MBin.Apr_m + MBin.May_m + MBin.Jun_m + MBin.Jul_m + MBin.Aug_m + MBin.Sep_m + MBin.Oct_m + MBin.Nov_m + MBin.Dec_m + MBin.Aft16 + b1 \times MEcon.ManEmp$

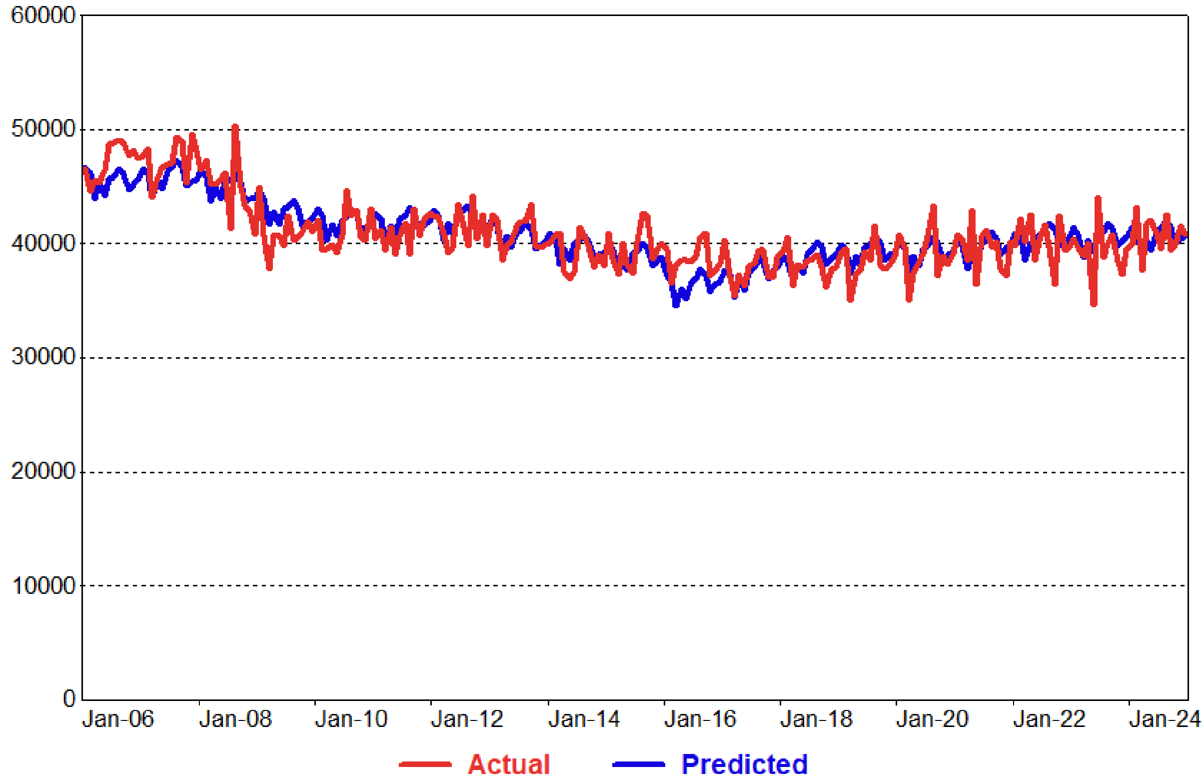
A binary variable for 2016 and subsequent years was added for improved model fit as the historic sales trend transitioned from declining to flat. As discussed in Section 4.0, a historic period of 2006–2024 was used to improve model fit.

Variable	Coefficient	StdErr	T-Stat	P-Value
MBin.Jan	20853.444	1440.731	14.474	0.00%
MBin.Feb	20342.822	1439.895	14.128	0.00%
MBin.Mar	18241.872	1439.059	12.676	0.00%
MBin.Apr	19690.529	1438.223	13.691	0.00%
MBin.May	18751.767	1437.387	13.046	0.00%
MBin.Jun	20290.360	1436.551	14.124	0.00%
MBin.Jul	20586.874	1435.715	14.339	0.00%
MBin.Aug	21309.030	1435.226	14.847	0.00%
MBin.Sep	20707.469	1434.738	14.433	0.00%
MBin.Oct	19214.808	1434.250	13.397	0.00%
MBin.Nov	19675.191	1433.761	13.723	0.00%
MBin.Dec	19915.116	1433.273	13.895	0.00%
MBin.Aft16	-2583.528	238.997	-10.810	0.00%
MEcon.ManEmp	654.003	40.038	16.335	0.00%

Medium Industrial Model Statistics

Model Statistics	
Iterations	1
Adjusted Observations	228
Deg. of Freedom for Error	214
R-Squared	0.706
Adjusted R-Squared	0.688
AIC	15.021
BIC	15.232
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	-2,021.92
Model Sum of Squares	1,617,097,118.75
Sum of Squared Errors	673,218,447.49
Mean Squared Error	3,145,880.60
Std. Error of Regression	1,773.66
Mean Abs. Dev. (MAD)	1,337.85
Mean Abs. % Err. (MAPE)	3.28%
Durbin-Watson Statistic	1.507
Durbin-H Statistic	#NA
Ljung-Box Statistic	188.79
Prob (Ljung-Box)	0.0000
Skewness	-0.061
Kurtosis	3.039
Jarque-Bera	0.157
Prob (Jarque-Bera)	0.9244

Medium Industrial Model Fit



Combined Model for Commercial and Industrial DSM Coefficient

$NonResSales_m = b1 \times NonResEESavingsProfiled_m + b2 \times GenWtXHeat_m + b3 \times GenWtXCool_m + b3 \times GenWtXOther_m + b4 \times NonResCustomers_m + MBin.Feb18_m + MBin.Oct22$

Weighted X variables from the General Service model were used to represent the underlying end uses in conjunction with the non-residential portion of historical DSM savings, as well as the number of non-residential customers to help explain underlying sales trends over time. Binary variables were added for May and June 2020 and October 2022 for problems with the billing. Binaries were also added for February 2018 and for the years 2021-2024 to improve model fit.

Variable	Coefficient	StdErr	T-Stat	P-Value
MSales.EESavingsProfiled	-0.433	0.166	-2.616	1.01%
MStructGen.WtXCool	0.552	0.051	10.771	0.00%
MStructGen.WtXHeat	0.906	0.041	22.084	0.00%
MStructGen.WtXOther	0.976	0.328	2.976	0.36%
MSales.NonResCusts	3.620	1.278	2.833	0.55%
MBin.Feb18	33674.893	10976.318	3.068	0.27%
MBin.Oct22	39050.666	11034.367	3.539	0.06%
MBin.May20	-45125.298	11061.319	-4.080	0.01%
MBin.Jun20	-43630.113	11114.974	-3.925	0.02%
MBin.Yr21to24	-6009.765	2528.720	-2.377	1.92%

The coefficient on the EESavings variable represents the amount of DSM needed to explain historical sales trends beyond the changes in the underlying end-uses.

Combined Model Statistics

Model Statistics	
Iterations	1
Adjusted Observations	120
Deg. of Freedom for Error	110
R-Squared	0.852
Adjusted R-Squared	0.840
AIC	18.648
BIC	18.880
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	-1,279.13
Model Sum of Squares	73,583,915,334.83
Sum of Squared Errors	12,745,845,311.45
Mean Squared Error	115,871,321.01
Std. Error of Regression	10,764.35
Mean Abs. Dev. (MAD)	8,379.90
Mean Abs. % Err. (MAPE)	2.69%
Durbin-Watson Statistic	1.960
Durbin-H Statistic	#NA
Ljung-Box Statistic	41.82
Prob (Ljung-Box)	0.0135
Skewness	0.104
Kurtosis	2.650
Jarque-Bera	0.828
Prob (Jarque-Bera)	0.6609

Peak Forecast (Accrued Classes)

The long-term system peak forecast for the accrued classes is derived through a monthly peak linear regression model that relates monthly peak demand (excluding large customer contribution) to heating, cooling, and base load requirements, as well as average daily wind:

$$Peak_m = b1 \times HeatVar_m + b2 \times CoolVar_m + b3 \times BaseVar_m + b5 \times PkWindVar_m + \sum Binaries$$

The model variables ($HeatVar_m$, $CoolVar_m$, and $BaseVar_m$) incorporate changes in heating, cooling, and base-use energy requirements (which are derived from the class sales forecast models) as well as peak-day weather conditions.

The composition of the models allows historical and forecast heating and cooling load requirement to be estimated. The model coefficients for the heating (*XHeat*) and cooling variables (*XCool*) combined with heating and cooling variable for calendar-month normal weather conditions produce an estimate of the monthly heating and cooling load requirements.

Heating requirements are calculated as:

$$HeatLoad_m = B_1 \times ResXHeat_m + C_1 \times SmlGSXHeat_m + D_1 \times GSXHeat_m$$

Where *B1, C1*, and *D1* are the coefficients on *XHeat* in the Residential, Small General Service, and General Service sales forecast models.

Cooling requirements are estimated in a similar manner. Cooling requirements are calculated as:

$$CoolLoad_m = B_2 \times ResXCool_m + C_2 \times SmlGSXCool_m + D_2 \times GSCool_m$$

Where *B2*, *C2*, and *D2* are the coefficients on *XCool* in the residential, Small General Service, and General Service sales forecast models.

In constructing the monthly peak model variables, the heating and cooling load requirements are normalized for the number of days and hours in the month by expressing heating and cooling load requirements on an average MW load basis:

$$HeatAvgMW_m = HeatLoad_m / Days_m / 24$$

$CoolAvgMW_m = CoolLoad_m / Days_m / 24$

The impact of peak-day weather conditions are then captured by interacting peak-day HDD and CDD with average monthly heating and cooling load requirements. *HeatAvgMW* and *CoolAvgMW* are interacted with peak-day *HDD* and *CDD* indexes, which allows the impact of peak-day *HDD* and *CDD* to change over the estimation period as the underlying heating and cooling load requirements change.

The peak model heating and cooling variables are calculated as:

$HeatVar_m = HeatAvgMW_m \times PkHDDIdx_m$ $CoolVar_m = CoolAvgMW_m \times PkCDDIdx_m$

The peak model base load variable ($BaseVar_m$) is constructed to capture the impact of loads that are not weather sensitive on peak, including residential, commercial, other end-use components along with industrial and unmetered sales. Base load requirements are calculated as:

$BaseVar_m = \sum C_m \times mBin \times OtherLoad_m$

Where the C_m coefficients are regression coefficients associated with the portions of $OtherLoad_m$, corresponding to a specific month of the year. In this way $BaseVar_m$ measures the strength of the non-weather sensitive load drivers in each month of the year. $OtherLoad_m$ is comprised of:

$OtherLoad_m = ResOther_m + SmlGSOther_m + GSOther_m + SmIndSales_m + MedIndSales_m + UnMSales_m$

Where $ResOther_m$, $SmlOther_m$ and $GSOther_m$ are the non-weather dependent portion of the sales model (including embedded DSM). For example, the energy sales model can be written as:

$ResSales = b1 \times ResXHeat + b2 \times ResXCool + ResOther$

Where *b1* and *b2* are regression coefficients found after running the sales model. *ResOther* can be written as:

$ResOther_m = ResSales_m - b1 \times ResXHeat_m - b2 \times ResXCool_m$

In this way, $ResOther_m$ (and $SmlOther_m$ and $GSOther_m$) carries the non-weather dependent variables, including past energy-related DSM activity into the peak model, whose impact was assessed through specific coefficients in the energy sales model.

The $OtherLoad_m$ requirements are normalized for the number of days and hours in the month by expressing the load requirements on an average MW load basis:

$OtherAvgMW_m = OtherLoad_m / Days_m /24$

The $PkWindVar_m$ is the average daily windspeed on monthly peak days. Binaries are included for May and June 2020 and for October 2022 to account for the impact of billing issues. Binaries for Februrary 2018 and June 2024 were added to improve model fit.

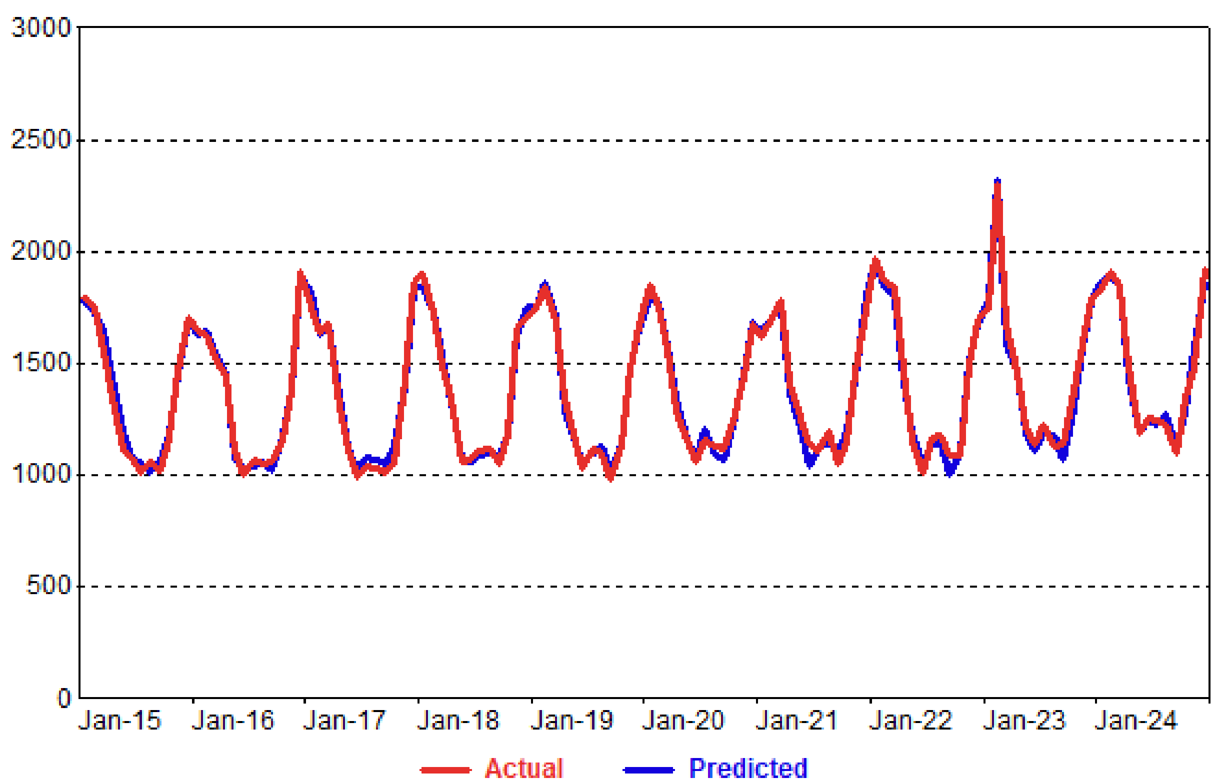
Variable	Coefficient	StdErr	T-Stat	P-Value
mVarsNew.Heat_Var	1.432	0.075	19.017	0.00%
mVarsNew.Cool_Var	0.865	0.160	5.397	0.00%
mVarsNew.Jan_Other	1.206	0.085	14.149	0.00%
mVarsNew.Feb_Other	1.179	0.100	11.737	0.00%
mVarsNew.Mar_Other	1.365	0.080	17.122	0.00%
mVarsNew.Apr_Other	1.570	0.050	31.515	0.00%
mVarsNew.May_Other	1.590	0.036	44.613	0.00%
mVarsNew.Jun_Other	1.688	0.034	50.369	0.00%
mVarsNew.Jul_Other	1.669	0.057	29.354	0.00%
mVarsNew.Aug_Other	1.521	0.067	22.801	0.00%
mVarsNew.Sep_Other	1.544	0.034	45.094	0.00%
mVarsNew.Oct_Other	1.641	0.032	50.612	0.00%
mVarsNew.Nov_Other	1.753	0.050	35.094	0.00%
mVarsNew.Dec_Other	1.631	0.079	20.610	0.00%
mPkDayWthr.PkWind	3.734	0.652	5.725	0.00%
mBin.Oct22	-277.504	45.034	-6.162	0.00%
mBin.Feb18	-133.810	44.518	-3.006	0.34%
mBin.Jun24	134.718	43.341	3.108	0.25%
mBin.Jun20	169.277	43.665	3.877	0.02%
mBin.May20	134.209	43.900	3.057	0.29%
MA(1)	0.287	0.104	2.752	0.71%

Peak Model Statistics

Model Statistics	
Iterations	13
Adjusted Observations	120
Deg. of Freedom for Error	99
R-Squared	0.985
Adjusted R-Squared	0.982
AIC	7.612520
BIC	8.100331
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	-606.02384
Model Sum of Squares	10,993,756.966
Sum of Squared Errors	171,101.463
Mean Squared Error	1,728.29761
Std. Error of Regression	41.57280
Mean Abs. Dev. (MAD)	30.55028
Mean Abs. % Err. (MAPE)	2.35%
Durbin-Watson Statistic	1.939
Durbin-H Statistic	#NA
Ljung-Box Statistic	17.04
Prob (Ljung-Box)	0.8470
Skewness	0.049
Kurtosis	2.657
Jarque-Bera	0.634
Prob (Jarque-Bera)	0.7283

Peak Model Fit

As seen in the figure below (and in the model statistics above), this approach produces a good fit with historical data. Although it was not possible to produce a peak model with an explicit peak DSM variable (like the Residential model) as the associated parameters are insignificant, the indirect effects of energy related DSM in the historical data from the end use model are carried over into the peak model. Assuming there is a relationship between the DSM applied to peak savings and DSM applied to energy savings, this will result in a similar amount of DSM embedded in the peak forecast, either through the embedded portion of energy sales DSM that is present on the $OtherLoad_m$ or embedded on the accrued demand information measured at the system level.



Appendix C

Forecast Comparison and Accuracy

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Figure C1: Total Nova Scotia Energy Requirement (NSR)

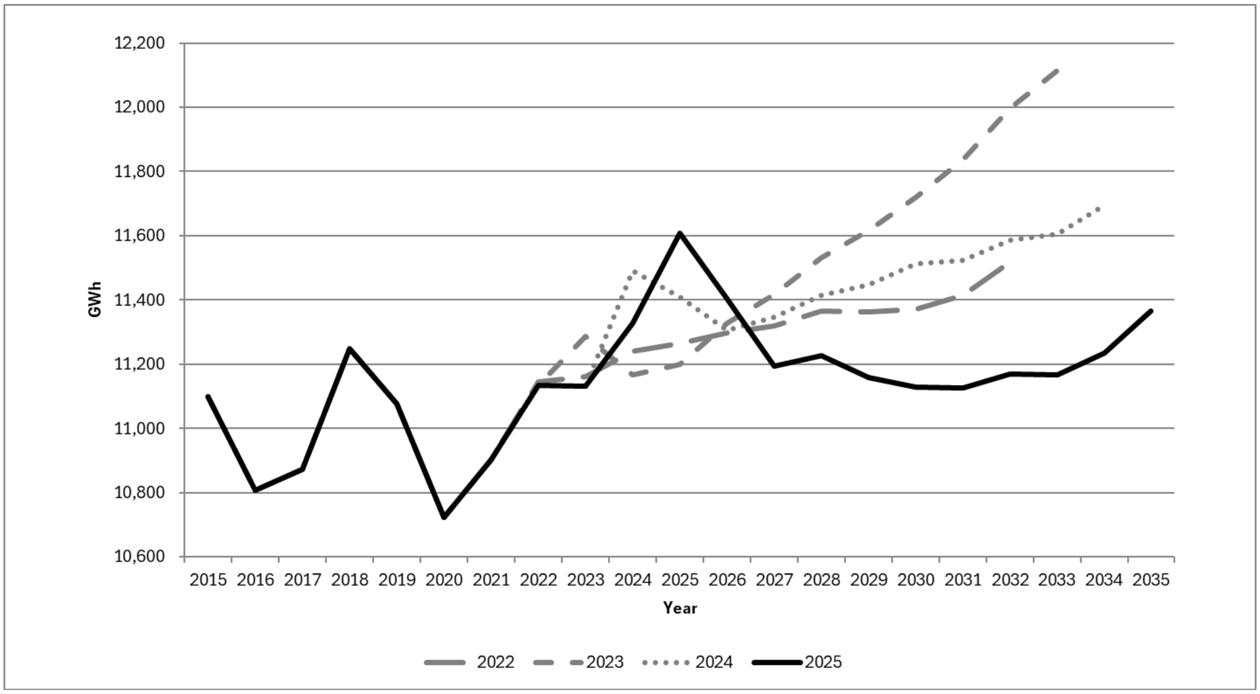


Figure C2: System Peak Demand

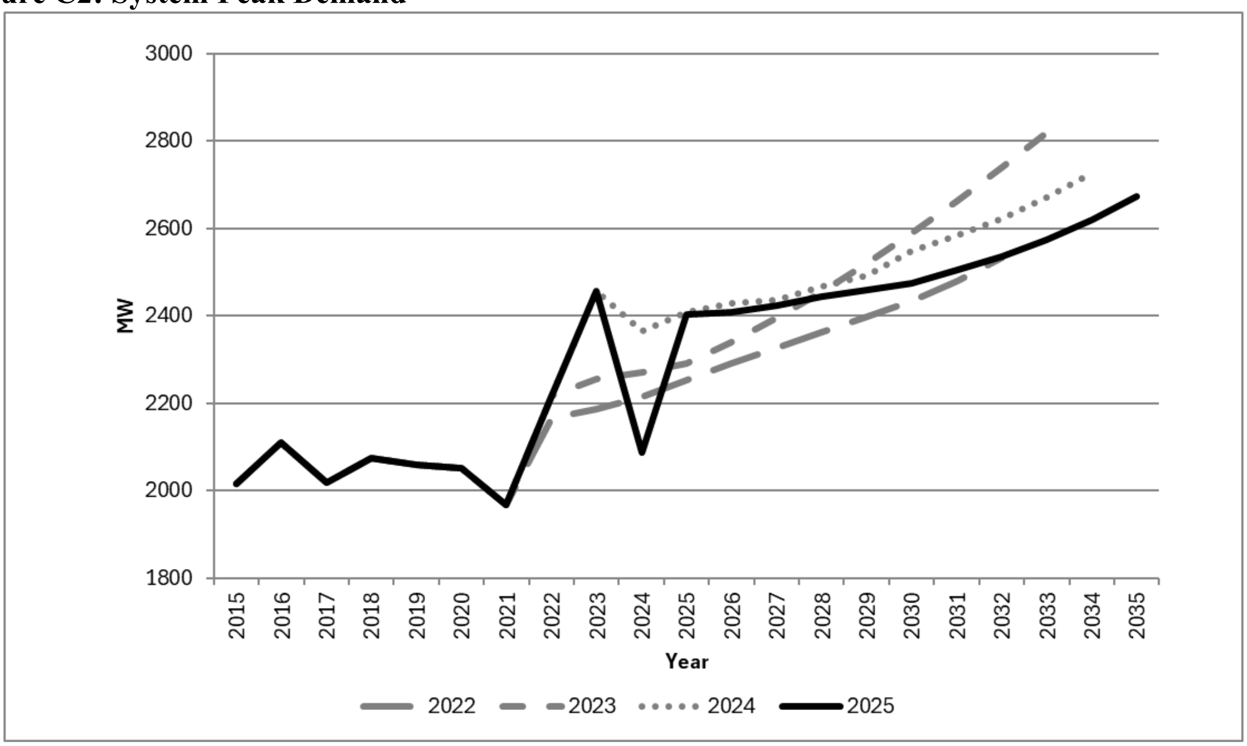


Figure C3: Firm Peak Demand

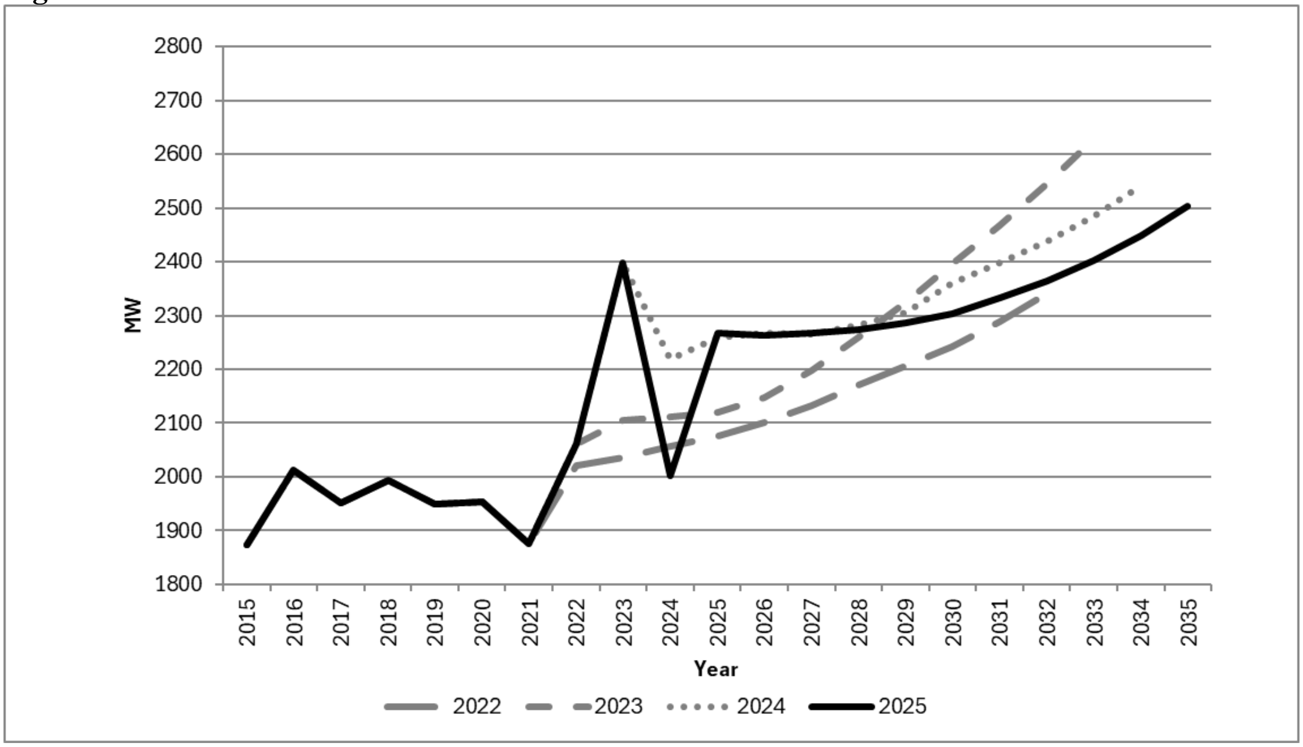


Figure C4 below provides an overview of the energy forecast accuracy. For these calculations, the load of the major pulp and paper mills is removed from the net system requirement as these contribute a significant amount of unforeseeable variance to the results. The rows show each years' 10-year forecast series with the forecast mill load removed. The row labeled "Actuals less mills" is the actual NSR with mill load removed. Each forecast year is compared to the corresponding actual value, and a 10-year average is calculated based on number of years out in the forecast series. So, a lead time of 1 would correspond to the average error of all the forecast first year estimates versus the corresponding actual value. The statistics show that on a 5-year basis the error (mean absolute percent error, or MAPE) averages just over 2 percent. Beyond 5 years the accuracy diminishes. **Figure C5** provides the same analysis for the firm peak load (the mills are not considered part of the firm load). As the peak is much more sensitive to weather, the error is larger, but averages just over 5 percent in the first 5-year period, with accuracy diminishing in later years. **Figure C6** provides the system peak accuracy, with an average of 5.6 percent in the first 5-year period.

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Figure C4: Energy Forecast Accuracy

NSR less mills										
Forecast	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:
Issued	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
2014	10101	10066	10063	10067	10076	10070	10071	10081	10139	10146
2015		10013	10036	10020	9986	9918	9833	9769	9731	9681
2016			10156	10180	10202	10233	10216	10235	10254	10282
2017				9931	9896	9920	9891	9902	9927	9954
2018					9944	9947	9860	9825	9779	9746
2019						10168	10171	10146	10108	10088
2020							10056	10109	10152	10200
2021								10011	10049	10121
2022									10117	10213
2023										10266
Actuals minus Mills	[redacted]									
Percent Error										
2014	0.1%	2.6%	2.0%	-0.9%	-1.4%	2.3%	1.4%	-0.9%	-3.1%	-3.9%
2015		2.1%	1.7%	-1.4%	-2.2%	0.7%	-1.0%	-4.0%	-7.0%	-8.3%
2016			2.9%	0.2%	-0.1%	3.9%	2.8%	0.6%	-2.0%	-2.6%
2017				-2.3%	-3.1%	0.7%	-0.5%	-2.7%	-5.1%	-5.7%
2018					-2.6%	1.0%	-0.8%	-3.5%	-6.5%	-7.7%
2019						3.3%	2.4%	-0.3%	-3.4%	-4.5%
2020							1.2%	-0.7%	-3.0%	-3.4%
2021								-1.6%	-3.9%	-4.2%
2022									-3.3%	-3.3%
2023										-2.8%

NSR less mills										
Forecast	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:
Statistics										
Lead Time (Years):	1	2	3	4	5	6	7	8	9	10
No. Observations:	10	9	8	7	6	5	4	3	2	1
Average percent Error:	-0.3%	-0.3%	-0.9%	-1.4%	-1.9%	-2.2%	-2.6%	-3.5%	-5.7%	-3.9%
MAPE:	2.2%	2.1%	1.6%	2.5%	3.1%	3.3%	3.3%	3.5%	5.7%	3.9%

Figure C5: Firm Peak Forecast Accuracy

Firm Peak										
Forecast	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:
Issued	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
2014	1940	1932	1916	1911	1907	1910	1899	1896	1894	1892
2015		1892	1896	1897	1889	1878	1859	1847	1837	1854
2016			1987	2009	2023	2033	2041	2051	2057	2060
2017				1993	2010	2029	2038	2054	2073	2080
2018					2001	2015	2016	2021	2028	2034
2019						2070	2073	2078	2080	2086
2020							2085	2053	2059	2064
2021								2062	2065	2060
2022									2035	2057
2023										2105
Actual Firm Peak:	1,861	2,014	1,951	1,993	1,949	1,954	1,875	2,061	2,397	2,001
Percent Error										
2014	4.2%	-4.1%	-1.8%	-4.1%	-2.2%	-2.3%	1.3%	-8.0%	-21.0%	-5.4%
2015		-6.0%	-2.8%	-4.8%	-3.1%	-3.9%	-0.8%	-10.4%	-23.4%	-7.3%
2016			1.8%	0.8%	3.8%	4.0%	8.9%	-0.5%	-14.2%	2.9%
2017				0.0%	3.1%	3.8%	8.7%	-0.3%	-13.5%	3.9%
2018					2.7%	3.1%	7.5%	-1.9%	-15.4%	1.6%
2019						5.9%	10.6%	0.8%	-13.2%	4.2%
2020							11.2%	-0.4%	-14.1%	3.1%
2021								0.1%	-13.9%	2.9%
2022									-15.1%	2.8%
2023										5.2%

Firm Peak										
Forecast	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:
Statistics										
Lead Time (Years):	1	2	3	4	5	6	7	8	9	10
No. Observations:	10	9	8	7	6	5	4	3	2	1
Average percent Error:	1.0%	-0.1%	-0.2%	-0.9%	-1.4%	-3.1%	-4.8%	-9.5%	-14.2%	-5.4%
MAPE:	5.2%	4.6%	5.0%	5.5%	5.8%	3.8%	7.5%	11.4%	14.2%	5.4%

Figure C6: System Peak Forecast Accuracy

System Peak										
Forecast	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:
Issued	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
2014	2078	2062	2057	2053	2051	2045	2042	2039	2048	2046
2015		2031	2035	2036	2028	2016	1997	1985	1975	1992
2016			2130	2156	2170	2180	2188	2197	2203	2205
2017				2149	2166	2184	2193	2208	2227	2234
2018					2157	2172	2174	2178	2184	2191
2019						2234	2243	2248	2249	2255
2020							2237	2212	2220	2230
2021								2225	2240	2247
2022									2185	2215
2023										2256
Actual System Peak:	2,015	2,111	2,018	2,073	2,060	2,050	1,968	2,216	2,455	2,088
Percent Error										
2014	3.1%	-2.3%	2.0%	-0.9%	-0.5%	-0.3%	3.7%	-8.0%	-16.6%	-2.0%
2015		-3.8%	0.9%	-1.8%	-1.6%	-1.7%	1.5%	-10.4%	-19.6%	-4.6%
2016			5.6%	4.0%	5.3%	6.3%	11.2%	-0.8%	-10.3%	5.6%
2017				3.7%	5.1%	6.5%	11.4%	-0.3%	-9.3%	7.0%
2018					4.7%	5.9%	10.4%	-1.7%	-11.0%	4.9%
2019						9.0%	14.0%	1.5%	-8.4%	8.0%
2020							13.6%	-0.2%	-9.6%	6.8%
2021								0.4%	-8.8%	7.6%
2022									-11.0%	6.1%
2023										8.0%

System Peak										
Forecast	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:
Statistics										
Lead Time (Years):	1	2	3	4	5	6	7	8	9	10
No. Observations:	10	9	8	7	6	5	4	3	2	1
Average percent Error:	3.3%	2.7%	2.7%	1.7%	0.9%	-0.8%	-2.5%	-7.3%	-10.6%	-2.0%
MAPE:	6.3%	5.2%	5.6%	5.3%	5.4%	3.4%	7.9%	11.0%	10.6%	2.0%

Appendix D

Forecast Sensitivity Analysis

Sensitivity Analysis

The P10/P90 sensitivity analysis used Monte Carlo simulation for the economic and weather variables. The algorithm uses the following sequence:

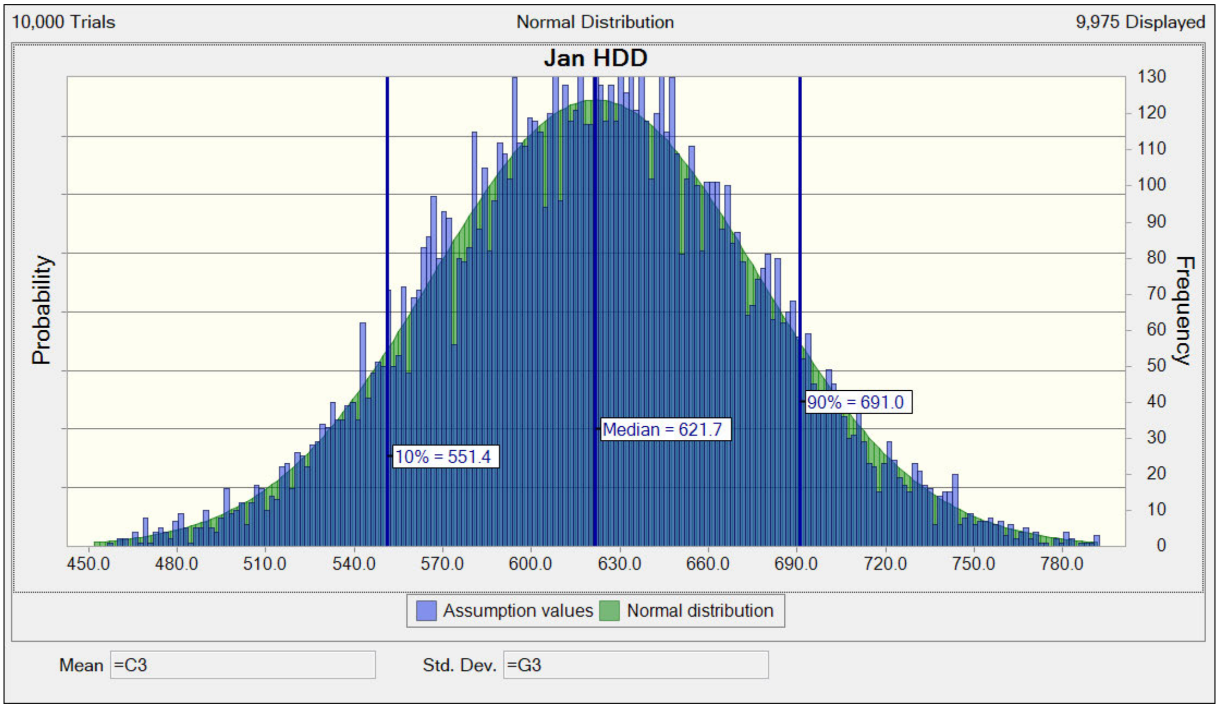
1. Once the deterministic SAE class regression models are completed, the regression coefficients are exported into the Monte Carlo tool, called Oracle Crystal Ball (MS Excel add-on).

2. The Monte Carlo process assumes that the regression coefficients are held constant throughout the simulation, the historical variation of the inputs (predictors, independent variables) will affect the forecast prediction, in a probabilistic way. In other words, the simulations help to understand how the underlying SAE forecast responds to changes to the inputs based on historical variation.

3. For 2024 the historical variation of monthly and peak day weather (20 years of hourly temperatures expressed in HDDs and CDDs) and economic drivers (20 years of annual data, as obtained from Conference Board of Canada Economic models) was used.

4. The variation of the weather and economic drivers is treated as Normal distributions (see **Figure D1**).

Figure D1: Distribution of January HDD



5. Oracle's Crystal Ball runs about 10,000 trials, taking a random set of numbers from the relevant variables for each trial. For example, the random HDD variable for January (above), would have a Normal distributed weight, meaning that after 10,000 trials, a histogram of the variable will have an average and standard deviation that coincides with the distribution of the last 20 years.

6. Incorporating variability in the individual end uses is still in progress, as it is difficult to produce a distribution for historical end use data. EIA and NRCan have revised their historical data sets in recent years, making historical variation studies challenging. However, as noted in previous sections, heat pumps are included in the input SAE models, and therefore their contributions to load will have an impact in the simulations as well.

7. At the end of the Monte Carlo run, 10,000 output forecast points are produced, each year represented by 10,000 possible outputs, with Normal distributed averages and standard deviations, which are the result of the different combination of the random variable trials.

These distributions are shown in **Figure D2** for energy and **Figure D3** for peak (both before the impact of DSM). 10th (10%) and 90th (90%) percentiles can easily be obtained from Normal distributions and so they are highlighted in D2.

Figure D2: Distribution of Energy (Before DSM)

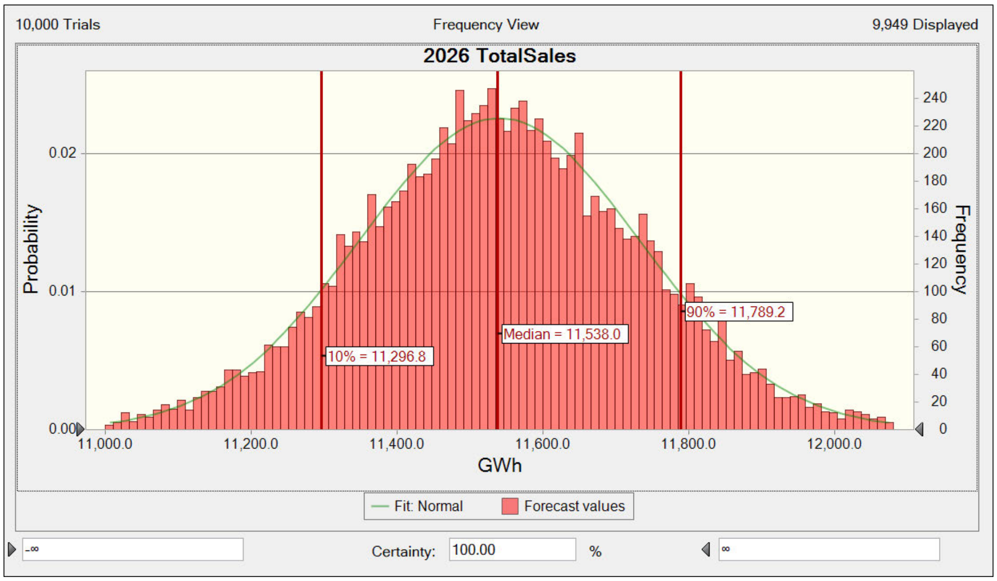
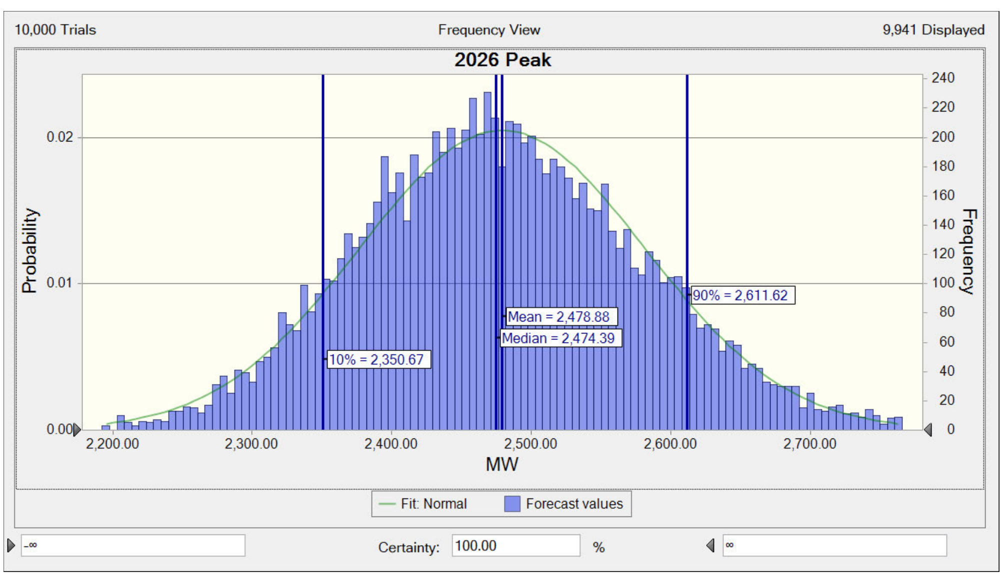


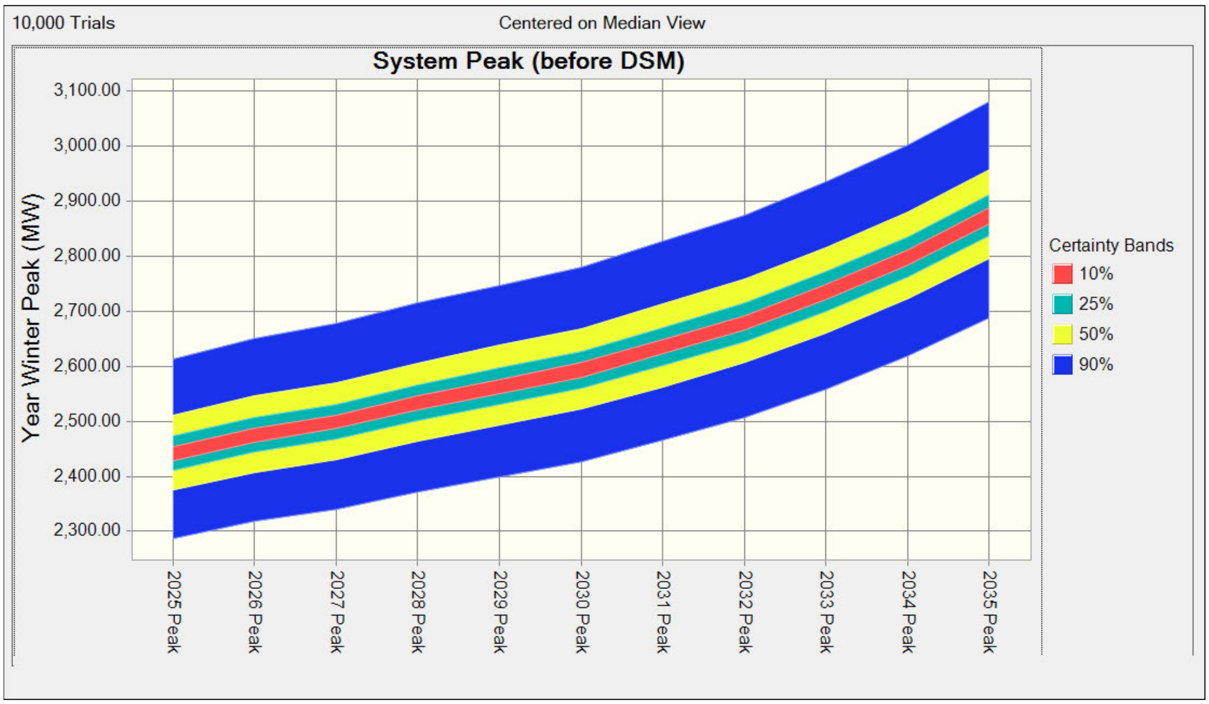
Figure D3: Distribution of Peak (Residential, Commercial and Small and Medium Industrial)



8. From these annual forecast distributions, the various probabilistic forecasts can be obtained as well as sensitivity diagrams that show the relative impact of the variables in each year.

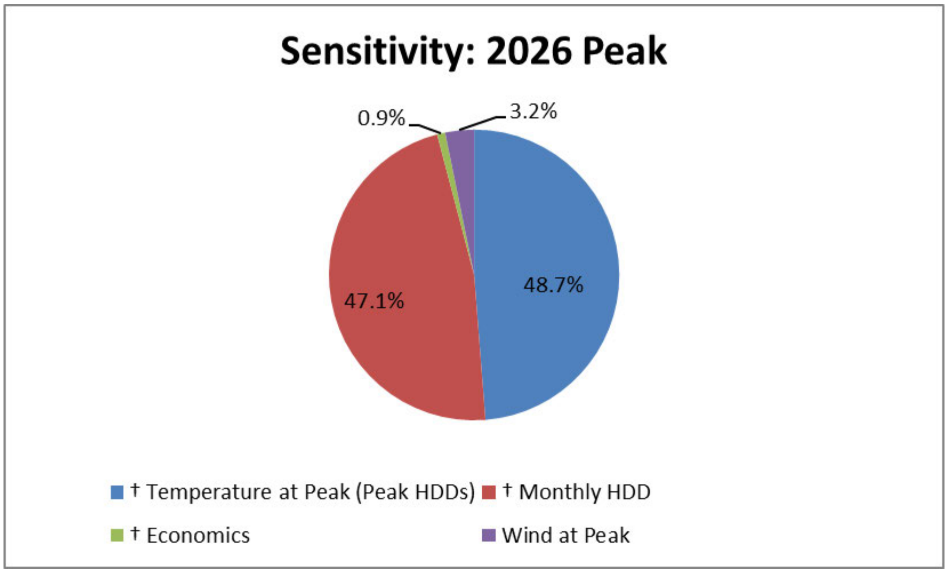
In **Figure D4** the probabilities of system peak forecasts (before DSM) around the median are shown. The area contained between blue borders represents a range of peaks that has a 90% chance of occurring; the yellow area highlights a 50% chance, and so on.

Figure D4: Peak Forecast (Residential, Commercial and Small and Medium Industrial)



The asymmetry in this figure, seen as the off-center median, is explained by the bias introduced by plotting the maximum monthly Peak of a given year. Every month has a normal distributed daily Peak HDD, however by using the MAX function a skewed quasi-normal distribution is created when it selects the maximum Peak HDD from the 12 available months. As shown in **Figure D5**, Peak Demand and its associated SAE model is as sensitive to Monthly HDD as it is the Peak HDD temperature (which is based on a 12-hour average). This is because year-long residential heating had an impact on sales, and therefore, that impact (sensitive to monthly variations) was translated into Peak Demand.

Figure D5: Relative Sensitivity of Peak



In terms of the sensitivity of the energy sales forecast to the various input variables, **Figures D6 and D7** show that in the near term, weather represents the strongest sensitivity, while in the long term, economics becomes equally as important as weather. This is mainly due to the compounding effect of economics over time, as opposed to weather which will only impact a particular year. By 2035 the cumulative impact of the economic variables makes economics rival weather in forecast sensitivity. The monthly (rather than cumulative) nature of HDD means it has much less relative impact in the long term.

Figure D6: Sensitivity of Energy Forecast (2026)

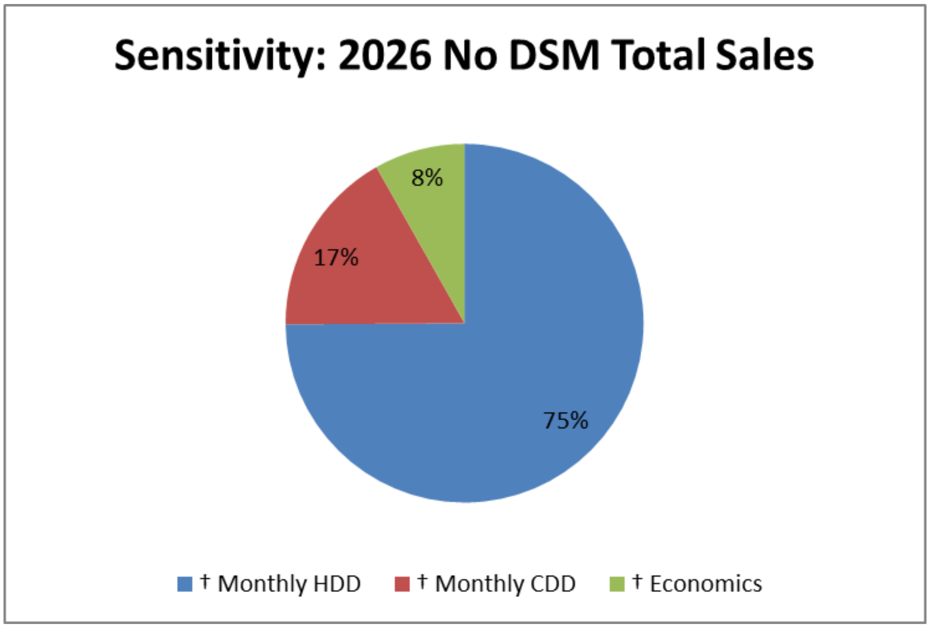
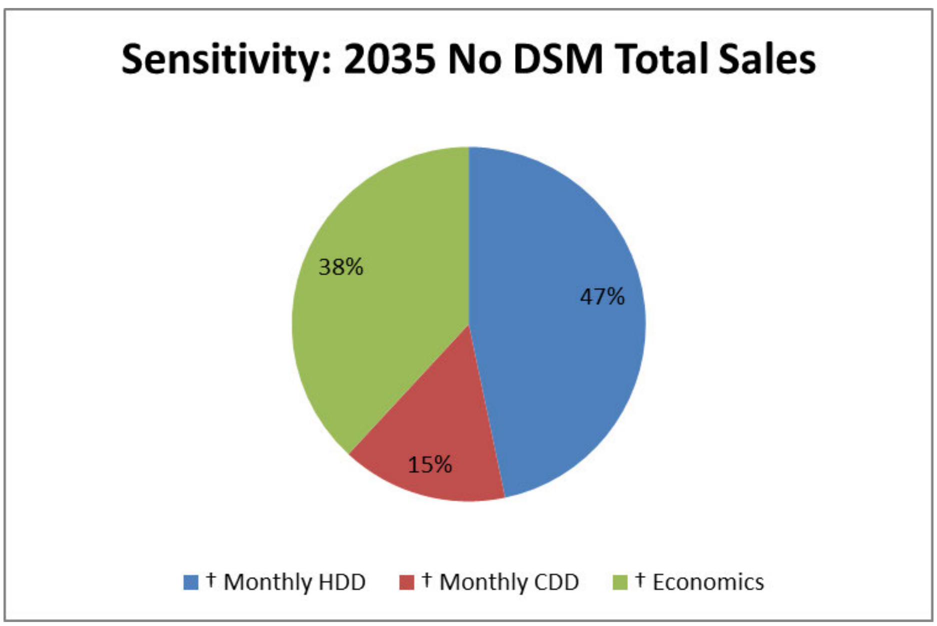


Figure D7: Sensitivity of Energy Forecast (2035)



In terms of relative magnitude of the sensitivities, DSM has the largest impact on both energy and peak demand, while Solar, [redacted] and EVs and potential hydrogen facilities could all have a significant impact on energy and EVs, hydrogen facilities and batteries could have a significant impact on peak. **Figure D8** shows the relative impact of these items.

Figure D8: Relative Impact of Inputs

Item	2025 Energy (GWh)	2025 Peak (MW)	2035 Energy (GWh)	2035 Peak (MW)
Included in Forecast				
DSM (base case)	-150	-26	-1456	-261
Solar PV	-148	0	-1023	0
[redacted]				
EV (current forecast)	32	5	740	109
Other Possible Scenarios				
EV (maximum non-coincident peak)	32	7	740	157
2 Hydrogen Production Facilities (firm supply portion)	0	0	650	130
Battery (5% share by 2035)	0	0	0	-140
Weather/Economics P10/P90	+/-244	+/-135	+/-324	+/-161
Price Elasticity of -0.3 (2x current elasticity of -0.15)	-17	-4	-140	-10

At this time, any potential impacts of the proposed hydrogen facilities on the NS Power's Net System Requirement and System Peak are still being evaluated. NS Power understands that two proposed projects have indicated a potential combined firm demand of 130 MW, which is reflected in **Figure D8**. In this sensitivity, the energy required by the facilities is assumed to be mostly self-supplied, with some top up supply from NS Power. The development of this new sector will continue to be monitored in future Load Forecast Reports.


Nova Scotia
POWER
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10-year Preliminary Load Forecast
April 8, 2025
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Purpose

As in previous years, this presentation on the preliminary 10-year load forecast provides an opportunity to discuss improvements and updates to the forecast and allow stakeholders to ask questions. This allows for feedback to be integrated in the final report and to ensure any outstanding issues are addressed.

Agenda

- Summary of Changes from 2024 Forecast
- Preliminary Results by Class
- Ongoing Work

Timeline

- October 2024: NSUARB Load Forecast Decision released
- December 2024 – March 2025: Forecast preparation
- April 2025: Stakeholder meeting to discuss updates and preliminary results
- April 30, 2025: 2025 Load Forecast Report submitted to the NSEB

Changes From 2024

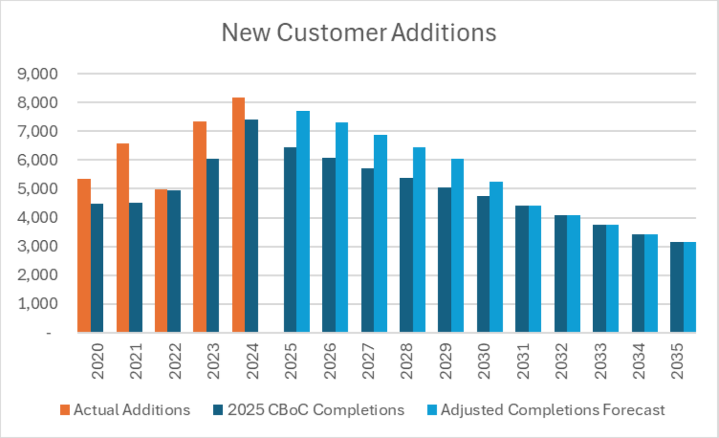
Input	Update
New Residential Load	New customer average load assumption updated using AMI data and customer segmentation
New Residential Customers	Review of Conference Board housing completions forecast
EV	EV average load and peak contribution updated using AMI analysis
Solar	Behind the meter solar generation adjusted as uptake continues to grow
RTR	Higher forecast RTR load, timing pushed out
COVID Variable	Residential COVID variable removed from forecast timeframe, commercial variable removed entirely

Average Consumption for New Customers

- In the Residential class, new customers are forecast based on new single family units (SFU) and multi-dwelling units (MDU), multiplied by average annual consumption for the two types of dwellings.
- In previous forecasts, the annual consumption was estimated at 16,000 kWh/year for SFUs and 4,860 kWh/year for MDUs.
- An updated analysis using AMI and customer segmentation data produced consumption estimates of 14,600 kWh/year for SFUs and 4,100 kWh/year for MDUs built after 2015.
- Over the 10 year timeframe of the forecast, this results in a drop of around 60 GWh in residential sales.

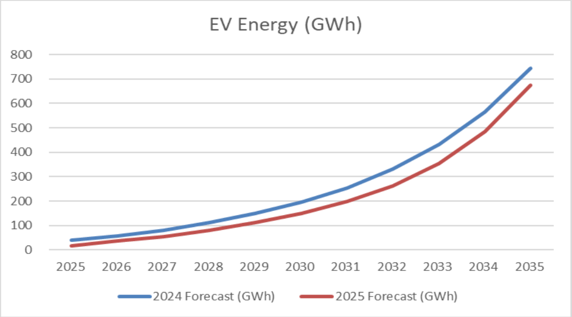
New Residential Customers

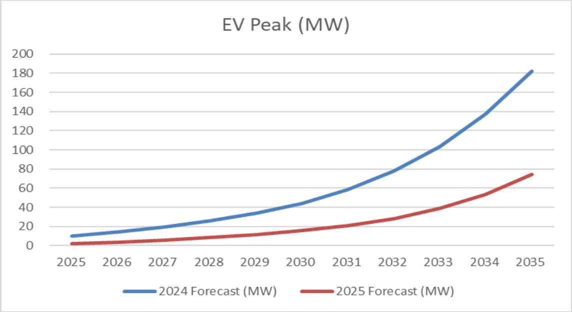
- New customers in the residential class are forecast using Conference Board of Canada's (CBoC) forecast for housing completions for single family and multi family units. Canadian Mortgage Housing Corporation data is not used directly.
- Comparing the CBoC historic forecasts to actual year over year change in customer number indicated that their forecast underestimated additions by around 20%. The current forecast has been adjusted accordingly over the 2025-2030 time period.



EV Load

- With the removal of both federal and provincial EV incentives, the forecast for EV sales has been adjusted downward compared to 2024 (around 40K less EVs on the road by 2035).
- Using AMI data from 2023 and 2024, the contribution of EVs to load and peak was evaluated based on a sample of customers who were identified as having an EV in 2024 but not in 2023. This data was compared to a control group to account for natural year over year changes in energy consumption.
- The results of the analysis were presented to EV industry participants for feedback. The result is an increase in the estimate for annual consumption (from 3485 kWh/year to 3820 kWh/year), and a reduction in peak contribution from 0.85 kW/vehicle to 0.39 kW/vehicle.





Behind the Meter Solar

- Small scale solar uptake continues to be strong: as of 2024 approximately 97 MW of solar generation has been installed (25 MW installed in 2024 compared to 20 MW installed in 2023).
- Rebates are still available for residential solar projects ($0.30/watt from the provincial programs).
- Net metering legislation will likely result in more interest from commercial customers.
- Given the continued strong uptake and changes to legislation, the long-term forecast has been adjusted to reflect increased solar penetration in the next 10 years – installed capacity of 934MW by 2035 (compared to 744MW in the 2024 forecast).

Renewable to Retail

- The 2024 forecast assumed that RTR sales would start in 2025, ramping up in 2026. The forecast has been updated to reflect a delay in startup (mid-2026) as well as an increased forecast for RTR sales.
- There is still uncertainty in the timing and magnitude of the RTR impact to sales.

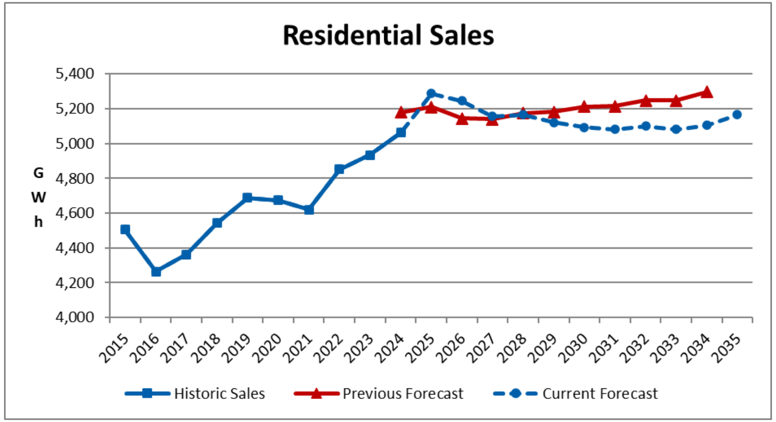
Class	2024 Forecast (GWh)	2025 Forecast (GWh)
Residential	75	117
Commercial	112	176
Industrial	59	128
Total	**246**	**421**

COVID Variables

- For 2025 the COVID variables have been updated in both the Residential and Commercial classes.
- In Residential, the variable remains in the model for the years 2020-2024 to help explain the change in usage over those years, but it has been removed from the forecast period as the regression model has the impact of increased work-from-home activity is sufficiently captured by the other model variables in future years.
- In the Commercial model the variable has been removed entirely as the other variables (primarily economic) sufficiently capture the impact to class sales.

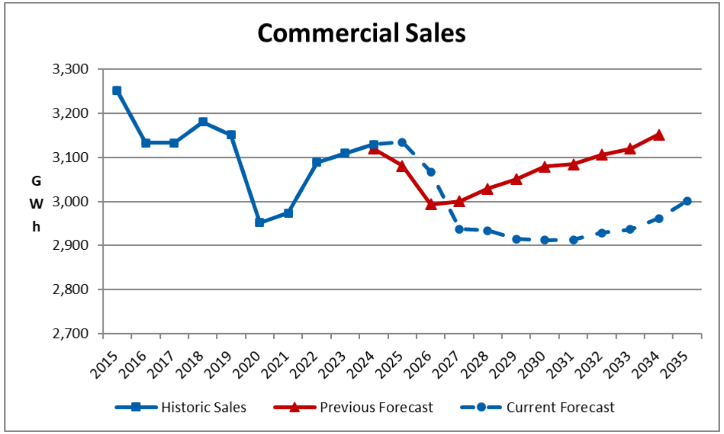
Forecast Comparison – Residential

- Sales in 2024 were lower than forecast due mainly to warmer than average weather. Over the forecast period, slower EV sales, increased behind the meter solar production, higher RTR sales will drive sales lower than forecast in 2024.



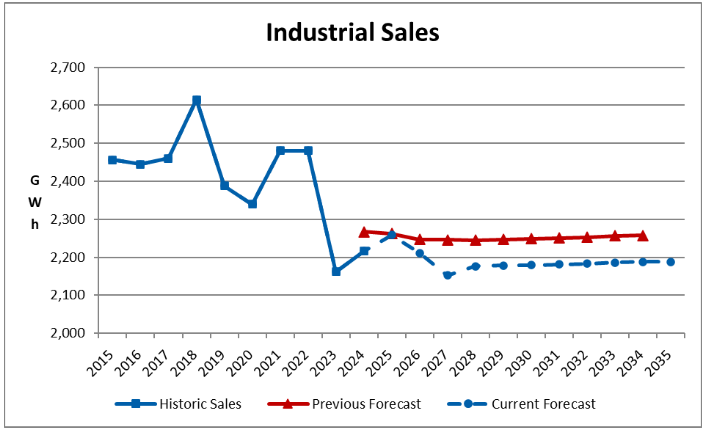
Forecast Comparison – Commercial

- Similar to the Residential forecast, Commercial sales will be impacted by slower EV sales, increased behind the meter solar production, and higher RTR sales than forecast in 2024.



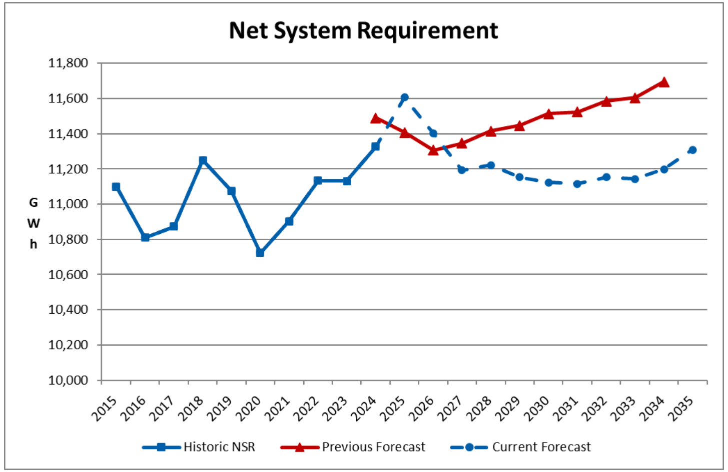
Forecast Comparison – Industrial

- Industrial sales show a decrease in 2026 and 2027 related to forecast RTR sales.



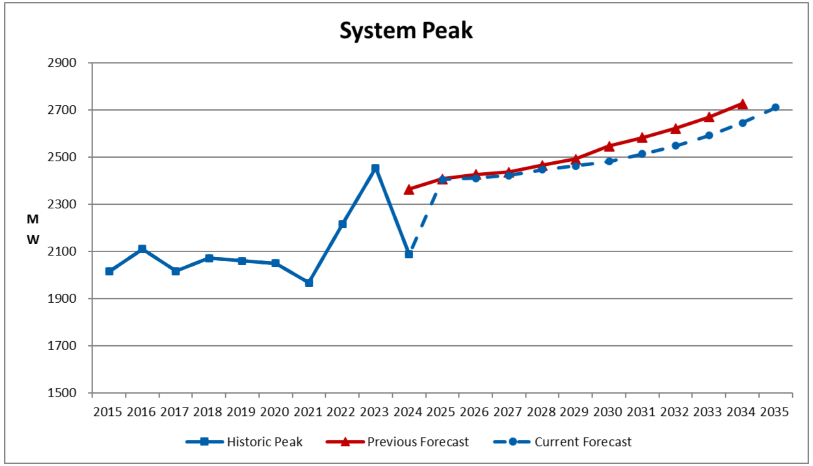
Forecast Comparison – Energy

- 2025 is expected to be higher than the 2024 forecast, with sales dropping in 2026 and 2027 as load shifts to the RTR market. Higher behind the meter solar and lower EV sales are expected to offset customer growth and electrification of space heating and result in flat sales until 2034.



Forecast Comparison – Peak

- The system peak forecast is similar to the 2024 forecast in the near term (RTR and behind the meter solar have no impact on peak demand), with a reduction starting in 2030 related to reduced EV sales and lower expected EV peak contribution.



2024 Forecast to Actuals

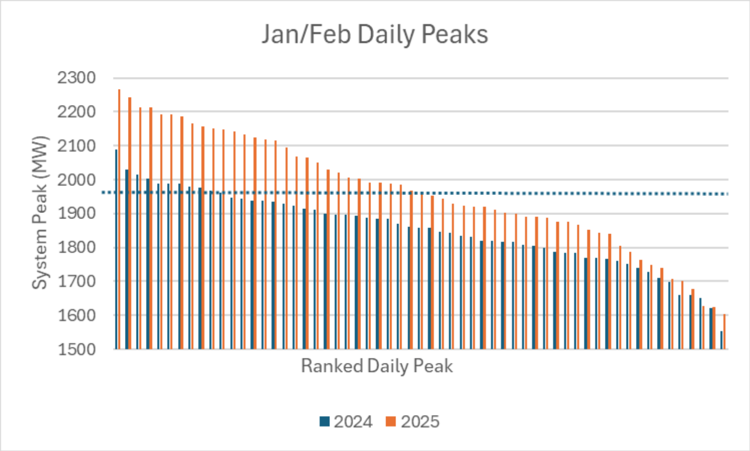
- Below is an estimate of the major variances between the 2024 forecast and 2024 actuals for both energy and peak.

Item	GWh
2024 Forecast NSR	**11,485**
Weather Impact	-134
Large Customer Actuals	-61
Other Variance	36
2024 Actual NSR	**11,326**

Item	MW
2024 Forecast System Peak	**2,365**
Interruptibles	-61
Weather (-10.8 12hr avg)	-101
Wind (avg 7.4 vs 18.8)	-31
Lighting (estimated)	-100
Other Variance	16
2024 Actual System Peak	**2,088**

2024 vs 2025 Peaks

- The warmer-than-normal weather in 2024 resulted in a lower than forecast peak load, as well as a small number of high-load days in Jan and Feb. Compared to 2025, which had colder than average weather, the number of days with system load above 2,000 MW increased from 4 in 2024 to 24 in 2025. The 2025 peak had a 12 hour average temperature of -12 degrees Celsius, slightly warmer than the forecast peak temperature conditions.



Ongoing Work

- Integration of AMI data
- Evaluation of the impact of electrification/emissions targets (hybrid heating project to start in 2025)
- Evaluation of the impact of new technologies as pilots progress (time variable pricing, direct load control)

2025 Load Forecast Report Attachments 1-10 has been filed electronically.