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Request IR-1:

Refer to Exhibit N-1, Nova Scotia Power Incorporated 2025 Load Forecast Report, (the "Report"), Section 4.1, Historical Class Sales and Energy Data, page 16 of 94 and respond to the following:

(a) Please explain the planned timeline for transitioning from "billed" sales to AMI-based "accrued" sales in the SAE models.

(b) Please indicate whether a specific forecast year is targeted for this transition and whether this shift will apply to all rate classes.

(c) Has NS Power conducted any back-testing or validation comparing billed sales and AMI-based accrued sales for 2024 or prior years? If so, please provide the results.

(d) Have small business customers (specifically those in rate classes 10, 11, and 21), who do not yet have AMI meters or are not fully connected to AMI infrastructure, been considered in the development of this transition?

Response IR-1:

(a-c) Please refer to NSEB IR-2 regarding work to incorporate AMI data into the estimation of accrued sales and integrate them into the load forecast models.

(d) Yes, processes developed to integrate AMI-based accrued sales will consider all customers not yet fully connected to the AMI infrastructure.

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Request IR-2:

Refer to Report, Section 4.3, Economic Information, page 27 of 94 and respond to the following:

The last paragraph states "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.[1]". Please explain the potential impact of this on the 2025 load forecast for class 21 (Small Industrial) customers.

(a) Specifically, please clarify how sensitive the forecast is to the manufacturing employment forecast input and whether any adjustments or alternative assumptions were considered.

Response IR-2:

(a) There is no impact to rate 21 as the forecast for that class depends on manufacturing GDP, not manufacturing employment.

[1] Exhibit N-1, Nova Scotia Power Incorporated 2025 Load Forecast Report, Page 27 of 94, Line 12-15

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Request IR-3:

Refer to Report, Section 4.4.1, Heat Pumps, page 34 of 94 and respond to the following:

(a) Please list all the provincial and federal heat pump incentives assumed to be available to commercial customers in the development of the 2025 Load Forecast. This should include any rebates, grants, subsidies, or financing programs considered, along with their respective eligibility criteria, incentive values, and assumed start/end dates.

(b) Please confirm whether the forecast be different without the incentives? Explain.

Response IR-3:

(a-b) As described on page 34 of the Report, the commercial space heating saturation forecast is based on the E3 electric heating stock model. This model does not consider specific incentives, it assumes sufficient update of electric heating to meet net zero by 2050 goals, implying that government policy would institute whatever incentives/requirements are needed to meet those goals.

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Request IR-4:

Refer to Report, Section 4.4.2, Water Heaters, page 37 of 94 and respond to the following:

The section states, at lines 12-14, that "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." Please identify any DSM incentives or provincial/federal code and standard changes that are assumed to drive these efficiency improvements for commercial customers.

(a) Please include the assumed effective dates and associated impacts, if available.

Response IR-4:

(a) There are no specific incentives assumed in the forecast that drive improvements in water heater efficiency. Rather, as noted in the Report, efficiency improvements are assumed to be the result of natural stock rollover from less-efficient to more-efficient units.

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Request IR-5:

Refer to Report, Section 4.4.4, Solar Generation (PV), page 44 of 94 and respond to the following:

(a) Figures 31 and 32 show that the average peak load per customer is higher for net-metering customers compared to non-net-metering customers during both summer and winter periods. What percentage of all NS Power's customers are net-metering customers and how many are non-net-metering customers?

Response IR-5:

(a) As of December 31, 2024, approximately 2 percent of customers are active net metering participants, and 98 percent are non-net-metering customers.[1]

[1] Please refer to Attachment 1 of the 2024 Net Metering Report (M12165) and the 2024 Commercial Net Metering Program Report (M12164).

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Request IR-6:

Refer to Report, Section 4.4.4, Solar Generation (PV), page 43 of 94 and respond to the following:

(a) Of the new behind-the-meter (BTM) solar installations projected for 2025–2035 in Figure 30, approximately what percentage is attributed to customer classes 10 (Small General), 11 (General), and 21 (Small Industrial)?

(b) Were any incentives or barriers, such as net-metering caps, interconnection costs, or solar subsidies, explicitly considered in developing these projections?

(i) If so, please describe the assumptions, eligibility by class, and the timing of these factors.

Response IR-6:

(a) Commercial installations are forecast to represent approximately 3 percent of total new installs in 2025, increasing to 6 percent of total new installs by 2035. Small General installs are forecast to represent approximately 0 percent of total new installs in 2025 increasing to 1 percent by 2035, while General installs represent approximately 3 percent in 2025 increasing to 5 percent by 2035. Small Industrial is not assumed to have any significant portion of solar installs by 2035.

(b) There are no specific assumptions regarding incentives, barriers, caps, interconnection costs or subsidies explicitly considered in the forecast beyond those outlined on page 42 of the report. Any current programs are expected to remain in place, and growth is assumed to continue at approximately 15 percent increase in installs per year.

Request IR-7:

Refer to Report, Section 4.5, Price Data, page 52 of 94 and respond to the following:

(a) These price 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. What percentage of small businesses are in the TVP pilot program (over the forecast period)? Can you provide information about the subsets of customers enrolled in the pilot program?

(b) The price elasticity values have changed significantly from the 2024 Load Forecast Report, ("2024 Report") M11689, Exhibit N-1, Section 4.5 Price Data, pages 51 – 53 of 100. Please provide data and/or calculations as to why these have changed significantly.

Response IR-7:

(a) In the Year Three (2023/24) TVP Evaluation Report, there were 65 commercial customers in the TVP pilot program.[1] Among the 65 commercial customers, 37 were enrolled in Small General TOU, 3 in Small General CPP, 19 in General TOU, and 6 in General CPP, representing a total of approximately 0.17 percent of the combined rate class population. Price elasticity has not been evaluated for this subset of customers, due to there being too few data points to analyze elasticity, as reported in the Company's Year Three TVP Report.[2]

(b) Although the methodology has remained consistent, the number of participants in the TVP pilot, and therefore included in the annual evaluation process, has increased significantly

[1] M11823 – NS Power, TVP Pilot Program 2023/24 (Year Three) TVP Evaluation Report, Appendix A, page 12 of 64, Table 5. July 31, 2024.
[2] M11823 – Appendix A, page 43 of 64.

– i.e. from 1,264 to 3,163.[3] With such a substantial increase in TVP participation, it is reasonable to expect notable shifts in elasticity. Even in the absence of major participation level changes, price elasticities at a macro level are inherently sensitive to factors beyond the control of the TVP pilot program, such as broader economic conditions.

[3] M11823 – Appendix A, page 12 of 64, Table 5.

Request IR-8:

Refer to Report, Section 4.6, Renewable to Retail, page 56 of 94 and respond to the following:

(a) Will RTR-supplied electricity result in higher total energy costs for participating small business customers relative to standard NS Power supply?

(b) Please provide the expected per-kWh cost comparison, including charges for balancing or backup services.

(c) If the RTR project experiences construction delays or fails to meet its 2027 in-service date, how will this affect forecasted energy allocations, rates, and system costs, particularly for non-participating customers in the small business classes?

(d) Please identify the wind generation source referenced on pages 55-56.

(i) Have any other suppliers submitted applications to NSUARB for approval?

(ii) If yes, identify these applicants and provide the status of those applications.

Response IR-8:

(a-b) The charges for Renewall electricity supply will be set by Renewall so NS Power is unable to comment on the total cost of RTR-supplied electricity compared to NS Power supply. Renewall provided as part of M10293 rate comparison information for 2024 in exhibit R-10(ii). Usage information of the customer will impact the average cost of energy for a Small General customer being served by the LRS or NS Power given that there is a customer charge and different energy charges based on usage. The Energy Balancing Service Tariff and Standby Service Tariff provides the charges and credits applied to the LRS for balancing and backup services.

(c) With respect to non-participating customers, rates are based on forecasts as established through General Rate Applications and other rate proceedings (e.g. FAM AA/BA Riders). To the extent actual LRS activity varies from the forecast-based pricing, these variances will be reflected in the Company's financials for non-fuel-related costs and in the FAM for fuel-related costs. With respect to participating customers, please see the above response. Note, non-participating customer costs may be affected by the RTR Energy Balancing Service and Standby Service tariffs and the Renewable to Retail Transition Tariff set annually as part of the Annually Adjusted Rate process.

(d) The wind generation source is the Mersey River Wind project submitted by the Licensed Retail Supplier (Renewall). NS Power is not aware of any other suppliers that have submitted applications for a Renewable to Retail Supplier License.

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Request IR-9:

Refer to Report, Section 10.0, Peak Demand, page 76 of 94 and respond to the following:

(a) What are the EV assumptions for the small business classes and what percentage of the EV load is from small businesses?

(b) What assumptions have you made about demand response and similar programs and how would the system peak change if customers did not participate?

Response IR-9:

(a) Please refer to Synapse IR-9 Attachment 1 for the breakdown between residential and commercial EV charging. The commercial EV charging portion is assumed to be 20 percent in the Small General class and 80 percent in the General class.

(b) As shown in Figure 60, demand response programs include 6 MW of demand reduction by 2035 from Business, Non-profit, and Industrial Curtailment category. Commercial customers are also expected to contribute to the TVP Rate category but not significantly based on enrolment numbers to date. Without participation, and without other mitigation efforts, system peak would increase by the amount of the demand response programs outlined in Figure 60.

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Request IR-10:

Refer to Report, Section 10.0, Peak Demand, page 78 of 94 and respond to the following:

(a) **NS Power is working with E1 on a two-phase Eco Shift pilot project to investigate automatic and manual control of various loads for commercial and industrial customers. What percentage of the Eco Shift pilot are small businesses?**

(b) **When will the 2025 results be released?**

Response IR-10:

(a-b) NS Power is not in possession of the information requested. Inquiries related to the specifics of the Eco Shift program should be sent to E1.

Request IR-11:

Refer to Report, Section 10.0, Peak Demand, page 83 of 94 and respond to the following:

(a) At lines 1-2, NS Power states: "As discussed in Section 4.4, the EV contribution to peak is expected to be partially mitigated via utility managed charging". What does "Utility Managed" mean?

(i) Is this a demand response program?

(b) How does the Utility Managed charging program affect EV charging for small business customers?

Response IR-11:

(a) Utility managed charging would be similar to the active control of EV charging tested in the Smart Grid Nova Scotia Project, where EV charging time and power was controlled directly by the utility; or where charging is influenced by time-varying rates or some combination of the two.

(i) Active control of EV charging and passive control (influenced by time-varying rates) would typically be considered a demand response program.

(b) Today, small business customers who shift EV charging load in response to time-varying pricing would be managing their EV charging contribution to peak and also would be eligible to enroll their business to shift EV charging demand in the Smart Synergy program from Efficiency Nova Scotia as well.

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Request IR-12:

Refer to Report, Section 10.1, Analysis of 2024 Actual Peak, page 84 of 94 and respond to the following:

(a) Figure 67, at lines 13-14, does not have a legend. Please confirm which is morning, and which is evening peak?

(i) What do the data points represent?

Response IR-12:

(a) Morning peaks are the blue dots, evening peaks are the orange dots.

(i) The data points represent 2024 hourly non-industrial loads for winter weekdays at 8:00 AM and 6:00 PM at various temperatures.

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Request IR-13:

Refer to Report, Section 10.3, End Use Peak Estimates, pages 86-87 of 94 and respond to the following:

For Figures 69 (on page 86) and 70 (on page 87), why does the EV peak contribution increase more for Commercial End-Use than for Residential from 2025 to 2034?

(a) Please provide the workbook for this data?

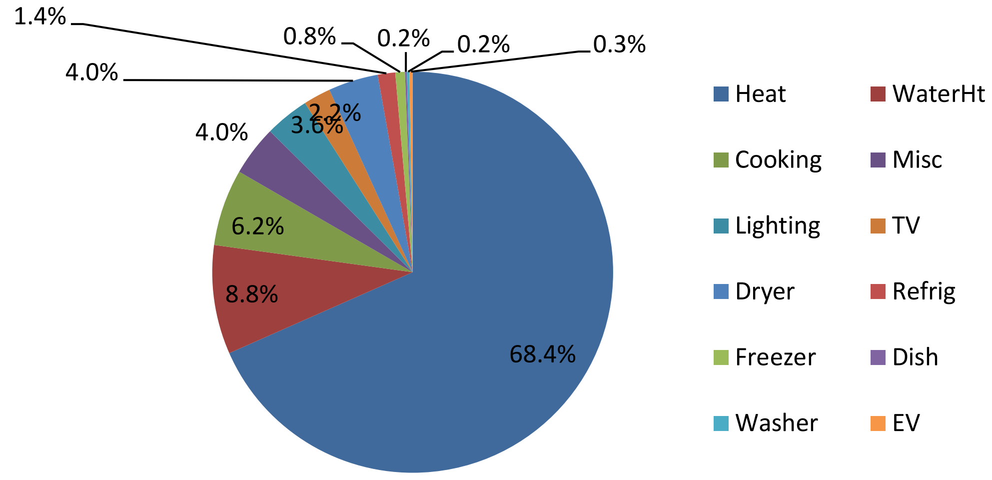
Response IR-13:

The change in peak contribution for specific end uses, as a percentage, is impacted by changes in the peak contribution of all other end uses in the class. Although this value is greater for commercial EVs than residential (6.2 percent vs 4.6 percent), the actual load increase is far smaller (39 MW vs 81 MW). Moreover, unlike the residential class, the commercial class exhibits less pronounced daily load peaks – due to more consistent heating usage throughout the day, for example – making the peak impact from electric vehicles comparatively more significant.

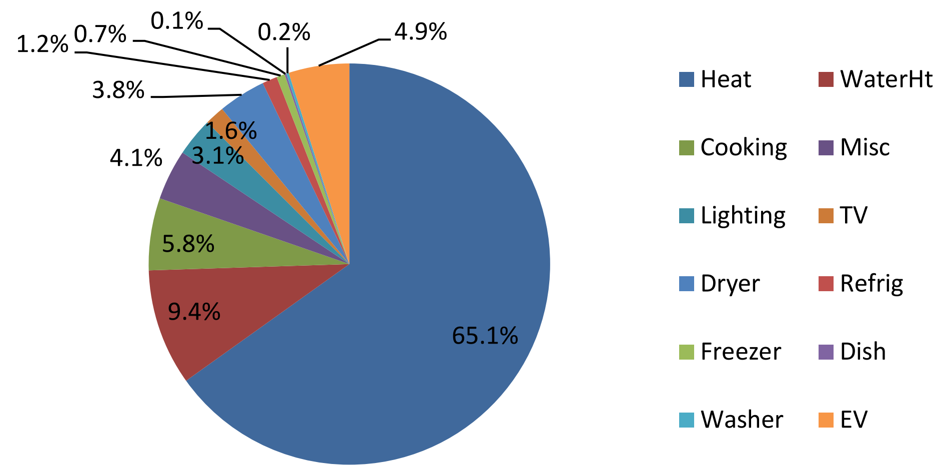
(a) Please see Attachment 1 for source data for Figures 69 and 70.

	Year	Heat	WaterHt	Cooking	Misc	Lighting	TV	Dryer	Refrig	Freezer	Dish	Washer	EV	Total
2025 Residential End Use Peak Shares	2025	1031.43	132.48	93.23	61.01	53.87	33.26	60.71	21.24	11.67	2.27	3.12	3.9	1508.20
2034 Residential End Use Peak Shares	2034	1129.81	162.73	100.92	70.49	53.96	27.36	66.45	20.90	11.53	2.45	3.54	84.8	1734.94
	2025	68.4%	8.8%	6.2%	4.0%	3.6%	2.2%	4.0%	1.4%	0.8%	0.2%	0.2%	0.3%	
	2034	65.1%	9.4%	5.8%	4.1%	3.1%	1.6%	3.8%	1.2%	0.7%	0.1%	0.2%	4.9%	
		-3.3%	0.6%	-0.4%	0.0%	-0.5%	-0.6%	-0.2%	-0.2%	-0.1%	0.0%	0.0%	4.6%	

2025 Residential End Use Peak Shares

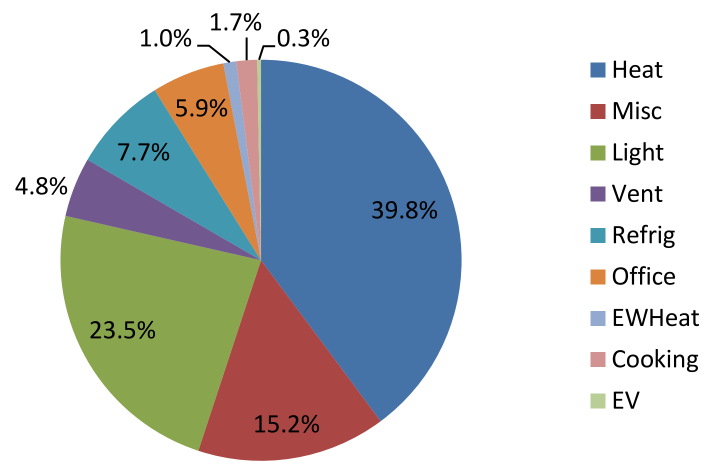


2034 Residential End Use Peak Shares



	Year	Heat	Misc	Light	Vent	Refrig	Office	EWHeat	Cooking	EV	Total
2025 Commercial End Use Peak Shares	2025	218.73	83.67	129.01	26.42	42.54	32.27	5.70	9.16	1.70	549.2
2034 Commercial End Use Peak Shares	2034	267.56	85.22	118.35	21.28	41.58	35.81	5.43	9.07	40.60	624.9
	2025	39.8%	15.2%	23.5%	4.8%	7.7%	5.9%	1.0%	1.7%	0.3%	
	2034	42.8%	13.6%	18.9%	3.4%	6.7%	5.7%	0.9%	1.5%	6.5%	
		3.0%	-1.6%	-4.6%	-1.4%	-1.1%	-0.1%	-0.2%	-0.2%	6.2%	13.8%

2025 Commercial End Use Peak Shares



2034 Commercial End Use Peak Shares