Request IR-1:

Report Tables and Graphs

(a) Please provide in electronic spreadsheet format all tables and graphs with identification of the data source(s) that appear in the load forecast report and appendices, retaining all formulas and calculations. To the extent that any tables and graphs have already been provided in electronic spreadsheet format in one of the report attachments, please provide references to the associated attachment.

Response IR-1:

(a) Please find data locations for all figures and tables included in the 2025 Load Forecast Report and appendices in the table below:

Figure	**Location**
Figure 5-19, 23, 31, 32, 38, 39, 41, 44, 47, 51, 55, 61-64, 66, 67, 73, 76, A2, C1-C6, D8	Synapse IR-1 Confidential Attachment 1
Figure 1-3, 48, 52, 56, 65	2025 LFR Attachment 4, tab Graphs
Figure 20-21	Synapse IR-26 Attachment 1, tab HP stock
Figure 22	2025 LFR Attachment 3, tab Shares
Figure 40, 57-59	Synapse IR-20 Attachment 1, tab Graphs
Figure 42, 46	Synapse IR-18 Attachment 1
Figure 43	2025 LFR Attachment 4, tab Residential
Figure 45	2025 LFR Attachment 1, tab StructuralVars
Figure 49	2025 LFR Attachment 4, tab Small General
Figure 50	2025 LFR Attachment 4, tab General Demand
Figure 53	2025 LFR Attachment 4, tab Small Industrial
Figure 54	2025 LFR Attachment 4, tab Medium Industrial
Figure 60	2025 LFR Attachment 4, tab DR
Figure 68	Synapse IR-16 Attachment 1
Figure 69, 70	SBA IR-13 Attachment 1
Figure 71, 72	CA IR-3 Partially Confidential Attachment 1, tabs Peak Day and Monthly

1

Figure	**Location**
Figure 74, 75	Synapse IR-22 Attachment 1
Table A1	2025 LFR Attachment 4, tab Sector Summary
Model data in Appendix B	2025 LFR Attachments 5-10
Regression breakdowns in Appendix B	Synapse IR-1 Attachments 2-4
Figures D5-D7	Synapse IR-23 Attachment 1

2025 Load Forecast Report Synapse IR-1 Confidential Attachment 1 has been removed due to confidentiality.

2025 Load Forecast Report Synapse IR-1 Attachment 2 has been filed electronically.

2025 Load Forecast Report Synapse IR-1 Attachment 3 has been filed electronically.

2025 Load Forecast Report Synapse IR-1 Attachment 4 has been filed electronically.

Request IR-2:

System Peak (Section 1.0, p. 10).

(a) Refer to Figure 3. Please explain the main factors driving the high degree of change and volatility in the system peak in the years 2022-2025.

(b) Why did the system peak decline by approximately 14.9 percent in 2024?

Response IR-2:

(a) The main factors driving year-to-year change in system peak are temperature, wind, and timing (in terms of both weekday/weekend and morning/evening). Figure 64 of the Report demonstrates that normalizing for these factors results in a more linear fit.

(b) Please refer to NSEB IR-1 part (b) for discussion of factors behind the peak drop in 2024 relative to 2023.

Request IR-3:

Unexplained residential forecast variance (Section 2.0, pp. 12-13; Section 5.0, p. 57)

(a) The report notes the Board's direction in M11689 to "continue to investigate the unexplained variance between forecast and actual NSR for the residential sector." Later, the report indicates that "adjustments were made to the heating intensities last year to better capture the trends" underlying the "Other" variances. Please document and explain in detail the specific modifications that have been made to heating intensities, and please also provide any evidence further supportive of these changes to intensities (separate from the fact that changing intensities reduces the variances).

(b) Did NSPI consider any other changes to its modeling approach to reduce the unexplained variances in the residential NSR? Please address the reasonableness of any other approaches to reducing this variance and please explain why any alternative approaches weren't ultimately adopted.

Response IR-3:

(a) The intensities were changed for the 2024 Load Forecast and the results were discussed in Sections 4.4 and 5 of the Report, with the specific changes to heating intensity shown in Figure 22. The updated models were also tested against the most recent year of data, with the resulting statics shown in Figure 38 of the 2024 Report.

(b) As discussed in the 2024 Report, the variances were found to be predominantly in the winter months, leading to the conclusion that they were likely driven by the heating component of the model. As a result, other components were not investigated as possible causes of the variance.

Request IR-4:

Billed versus Accrued Sales and Regression Period (Section 4.0, p. 16)

(a) The report notes that it uses monthly billed sales data from January 2015 to December 2024 for the residential and commercial energy forecasts, sales data from January 2015 to December 2024 for Small Industrial, and sales date from January 2006 to December 2024 for Medium Industrial "to improve the fit." Please quantify the nature of the improved fit.

(b) In NSPI's view, are there any potential issues with utilizing different data periods for different class forecasts? Please explain in detail.

(c) In NSPI's view, does the fact that the Medium Industrial model fit is comparatively poor when estimated using the more recent ten-year period rather than the full eighteen years of data have any implications for its accuracy in rendering forecasts? Have NSPI's forecasts for Medium Industrial been comparatively less accurate than its forecasts for other classes in recent years?

(d) In NSPI's view, would it be reasonable to use the same period for Medium Industrial as for the residential, commercial, and Small Industrial classes (January 2015 to December 2024)? Please explain in detail.

(e) Please explain how large customer peak demand is separately forecast.

Response IR-4:

(a) Please refer to page 27 of the Report – as stated, using a longer period of monthly billed sales to estimate the medium industrial model results in a more statistically significant economic variable (P-value of 0.00 percent and T-stat of 16.34 for 18 years, vs P-value of

0.00 percent and T-stat of 4.61 for 18 years), and an improved model fit (adjusted R-squared of 0.688 for 18 years, vs 0.329 for 10 years).

(b) NS Power sees no issues with using a longer data period to train the medium industrial model. The goal is to ensure the best possible fit for the data used in the forecast. In contrast, limiting the training period to the 10 years used for other sectors could reduce the model's accuracy.

(c) No. The accuracy of the medium industrial forecast model estimated using 18 years of data is comparable to that of the other forecast classes estimated using 10 years of data, as demonstrated by the MAPE values in the table below. These values, reproduced from Appendix B, are supported by additional model performance statistics provided in that appendix.

Class	MAPE[1] (%)
Residential	2.05
Small General	3.53
General	2.32
Small Industrial	3.62
Medium Industrial	3.28

(d) No. Please see part (b) above for further discussion on this matter.

(e) Please refer to page 81 of the Report. 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 then added to the accrued class forecast to obtain the total system peak.

[1] Mean Absolute Percentage Error

Request IR-5:

Cloud Cover (Section 4.2.1, p. 23)

(a) Does NSPI have any concern about how accurately the SWin data from NASA, reflecting conditions in the Halifax area, effectively represents cloud cover across NSPI's service territory? Please explain in detail.

(b) Is NSPI aware of any alternative sources of data for cloud cover in its service territory?

(c) Has NSPI considered alternative approaches to modeling the effects of cloud cover within the regression framework apart from or in addition to include it as an independent variable (e.g., accounting for non-linear effects and/or accounting for interactive effects)? Please explain in detail.

Response IR-5:

(a) No. A large portion of the NS Power customer base is situated within the Halifax area, so any relationship between load and cloud cover would be apparent in the results.

(b) No. As stated in Section 4.2.1 of the Report, the Environment Canada Weather Station at Shearwater, which supplies other weather data used in the Load Forecast, was explored as a potential data source but cloud cover data is not available from there.

(c) No. As stated in section 4.2.1 of the Report, the results indicate that no significant impact was observed, so alternative approaches were not explored.

Request IR-6:

Economic Information (Section 4.3, pp. 24-27)

(a) Please refer to the directive from the Board's Decision in M11689 that is quoted on page 24 (lines 17-20) of the load forecast. Please explain how NSPI has considered each of the following in validating its use of housing completions for its near-term forecasting of new customers:

(i) The Statistics Canada's provincial population growth scenarios.

(ii) Changes to building and permitting such as the Housing Accelerator

(b) Aside from the historical underestimation of actual customer additions by approximately 20 percent over the previous five years, is there any additional justification for adjusting upward by 20 percent the Conference Board's forecast for housing completions for 2025-2030?

(c) How does NSPI know that the drop in manufacturing jobs in the 2025 CBoC forecast is the result of reporting and modeling changes rather than being reflective of an actual drop in employment? Has NSPI addressed the possibility that continued reliance on the 2024 forecast will result in an over-estimation of 2025 manufacturing employment? Please explain in detail.

(d) Why is the industrial forecast based upon an econometric framework while the commercial models do not use an econometric framework?

Response IR-6:

(a) As discussed on page 24 of the Report, new customer numbers correlate with housing completions, not with population. As discussed on page 26 of the Report, the adjustment of +20 percent made to the completions forecast from the Conference Board of Canada aligns with the projected additional developments in Halifax due to the Housing Accelerator.

(b) As discussed on page 26, this adjustment aligns with projections related to the Housing Accelerator.

(c) Please refer to NSEB IR-5.

(d) For the industrial class, economics are the predominant driver of energy use over the long term, so an econometric framework is appropriate for these models. On the other hand, consumption in the commercial class has a strong sensitivity to heating, cooling, and other loads, in addition to economics, and thus are better modelled by the bottom-up SAE approach.

Request IR-7:

COVID-19 Variable (Section 5.0, p. 57; Section 6.0, p. 63; Appendix B, p. 5; Attachment 05 EO)

(a) Please provide an explanation for the statement about the use of the COVID-19 quasi-binary variable in the residential model that it "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." What is happening, mechanically, within the SAE model to render the COVID-19 variable no longer necessary – changes in the estimation of the input values for the terms (e.g., XHeat), or something else?

(b) On what basis has NSPI determined the input values for the COVID-19 variables for 2020-2024 in the residential model (input values = 1, 0.5, 0.13, and 0.01).

(c) How do the input values for the COVID-19 variable used in this year's residential model differ from the values used in prior years' models? How does the overall estimation of historical COVID-19-related work-from-home consumption in the residential model differ in this year's model relative to the estimates in prior years' models? What are the implications of any such differences?

(d) Please explain how it is possible that the historical data in the General rate class model captures COVID impact to sales, whereas the historical data in the residential model does not sufficiently capture these historical impacts, necessitating the need for the use of the COVID-19 variable for the years 2020-2024.

Response IR-7:

(a) In the residential model the variable is still required in the historic period. However, as the annual average use has stabilized over 2023/2024/2025, there is no need to project any further step changes in the load related to COVID-19 because the regression will relate the existing underlying variables to sales and project values that should represent the current state of consumption.

(b) As there is no distinct metric to track the decline of the COVID-19 impact with respect to sales, the values were tested on a trial-and-error basis based on the resulting model statistics.

(c) The 2025 COVID variable has a smaller impact than previous versions. Comparing 2024 LFR Attachment 5 with 2025 LFR Attachment 5, the differences are as follows:

Year	2024 COVID Variable	2024 COVID Impact to Avg Use (kWh/year)	2025 COVID Variable	2025 COVID Impact to Avg Use (kWh/year)
2020	1 (Jul)	154	1 (Jul)	181
2021	1	307	0.5 (Aug)	287
2022	0.65 (Aug)	263	0.13 (Aug)	125
2023	0.65	200	0.01 (Aug)	27
2024	0.65	200	0.01	2
2025	0.65	200	0	0
2026	0.65	200	0	0
2027	0.65	200	0	0
2028	0.65	200	0	0
2029	0.65	200	0	0
2030	0.65	200	0	0
2031	0.65	200	0	0
2032	0.65	200	0	0
2033	0.65	200	0	0
2034	0.65	200	0	0

(d) The commercial model inputs include economic variables which follow the trend in sales over the COVID timeframe. These serve as a driver of the reduction in sales over the 2020-2024 time period.

Request IR-8:

Annual Consumption by Building Type (Section 5.0, p. 59; Appendix B, p.2)

(a) How do the assumptions about energy consumption by house type enter into the load forecast? Please provide a detailed response with reference to the full residential model presented in Appendix B.

Response IR-8:

(a) The energy consumption by building type only applies to new construction, which is divided into single family and multi family units. They are added to the total class consumption as number of new units x average consumption for each building type. The impact can be found in the table Residential Load – Post Regression on page 10 of Appendix B, in the column labeled "New Cust. Load."

Request IR-9:

Electric Vehicles (EVs) ((Section 4.4.3, p. 38-41)

(a) Please provide the source data and calculations behind Figure 26-29.

(b) Please specify the share of EVs in the forecast which are light-duty, non-plug-in hybrids, plug-in hybrids, and/or battery-electric.

(c) Please provide the method for estimating the total number of EVs.

(d) How did elimination on rebates affect the EV forecast?

(e) Besides the elimination of rebates, were there any other changes driving the differences between the 2024 and 2025 EV sales forecasts?

(f) For the AMI data collected over 2023 and 2024, please state the number of customers in the new EV owners group and the control group.

(g) Please state whether the 2025 EV forecast incorporates data from the Smart Grid Nova Scotia report.

(h) Please confirm whether managed charging is incorporated into the 2025 forecast. If it is not, please explain. If NS Power has forecasted managed charging, please provide this information.

Response IR-9:

(a) Data and calculations for Figures 26 – 29 can be found in Attachment 1 on the following tabs:

- Figure 26: sales comparison tab
- Figure 27: EV effect tab
- Figures 28 and 29: 2025 EV load forecast tab

(b) Please refer to Attachment 1, 2025 EV load forecast tab.

(c) The method for estimating the number of total EVs in the fleet makes use of Statistics Canada data *Vehicle Registrations, by type of vehicle and fuel type*[1] for data one year removed (e.g. currently available until 2023, published late in 2024). For the current year, quarterly *Canada Electric Vehicle Industry Insights* reports from S&P Global Mobility[2] that detail the quarterly ZEV percentage of new light duty vehicle registrations are used in conjunction with Statistics Canada *New Motor Vehicle Sales* data (now inactive)[3] to estimate the growth of the fleet within the current year. While new vehicle sales do not directly correlate with new registrations, given the relative volume, this estimate has been reasonable to date. The Statistics Canada *New Motor Vehicle Sales* data has recently been replaced with *New Motor Vehicle Sales, Monthly,*[4] which now includes fuel type by Province. It is expected that this data will be referenced going forward.

It is worth nothing that the data set *Electric Vehicle Registration Data*[5] published by Open Data Nova Scotia is not used as a data source as NS Power has concerns that the data has regular and obvious errors. Popular models that have multiple drivetrain options are susceptible to being included when they are gas driven or excluded even though they are ZEV (e.g. Mitsubishi Outlander PHEV), leading to uncertain reporting, and there are clearly models included in the data that are Hybrid Electric Vehicles (that do not operate on electricity only and cannot be plugged in to charge the battery).

[1] Statistics Canada. Table 23-10-0308-01 Vehicle registrations, by type of vehicle and fuel type
[2] Example report: https://www.spglobal.com/automotive-insights/en/blogs/2025/03/canada-electric-vehicle-industry-insights
[3] Statistics Canada. Table 20-10-0001-01 New motor vehicle sales, inactive
[4] Statistics Canada. Table 20-10-0085-01 New motor vehicle sales, monthly
[5] Open Data Nova Scotia. Electric Vehicle Registration Data

After estimating the current fleet, the forecast is interpolated from the policy mandate that in 2035 all new light duty vehicles sold will be ZEV, but that interim goals will follow a low adoption curve as there is no provincial ZEV mandate that corresponds with the federal interim goals (e.g. 60 percent of sales by 2030).

(d) The end of consumer ZEV rebates federally and provincially were accounted for in the Load Forecast by lowering the near-term adoption forecast to reflect early sales and registration data from Q1 2025 and smoothing the adoption curve out to the 2035 100 percent sales mandate. The net result was a 74 percent decrease in the number of ZEV registrations projected in 2025 when compared to the forecast published in April 2024.

(e) The end of the consumer carbon levy in Canada erodes the value proposition of driving an electric vehicle relative to an internal combustion vehicle by lowering the cost of consumer fuel for ICE vehicles (net effect including HST = 20.25 c/L on gasoline; 24.60 c/L on diesel fuel). This is considered but not used directly in the forecast as the results are too difficult to measure outside of monitoring sales volumes in the time following the policy implementation, which was only recently implemented in April 2025.

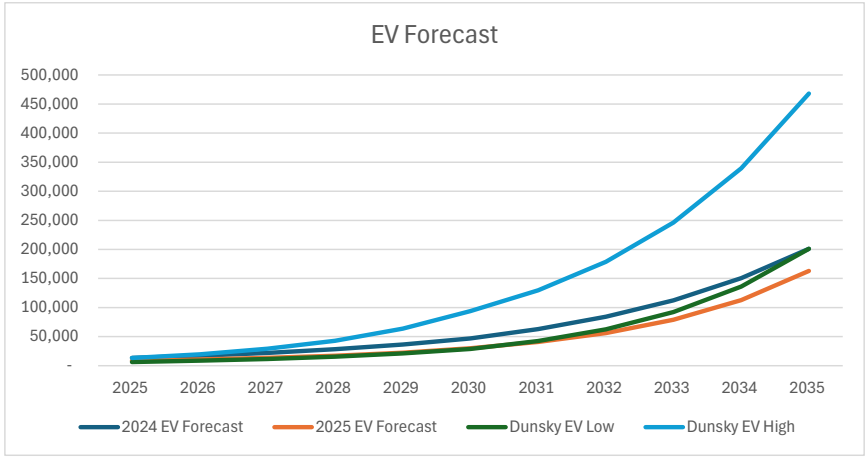
(f) The new EV owners group averaged 732 customers, and the control group averaged 1082 customers.

(g) The 2025 EV forecast does not incorporate any data from the Smart Grid Nova Scotia report.

(h) For this year's forecast, the peak impact of LDVs charging at home is updated according to the results of the analysis of AMI data outlined in Section 4.4.3, 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, which assumes managed charging of these vehicle types.

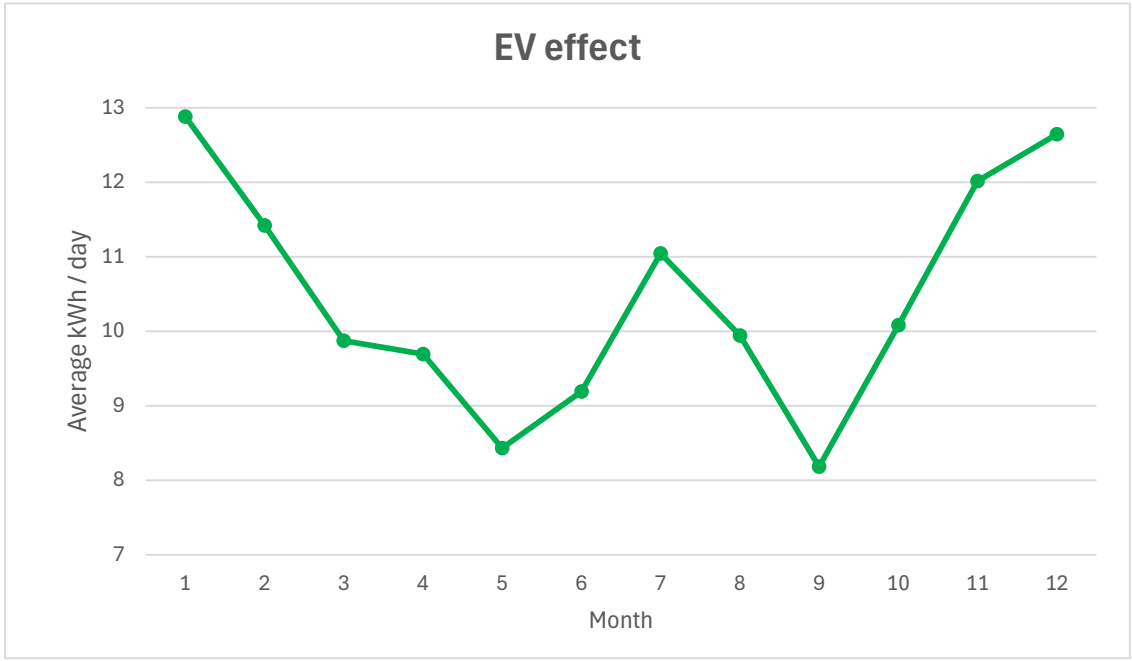
REDACTED (CONFIDENTIAL INFORMATION REMOVED)

	2024 EV Forecast	2025 EV Forecast	Dunsky EV Low	Dunsky EV High
2023	4,100	3,619	4,100	4,100
2024	7,391	6,769	5,200	8,700
2025	13,368	8,469	**6,300**	**13,300**
2026	17,188	10,612	8,538	19,666
2027	22,105	13,417	11,571	29,078
2028	28,434	17,208	15,681	42,995
2029	36,581	22,471	21,251	63,573
2030	47,068	29,930	**28,800**	**94,000**
2031	62,920	40,664	42,477	129,584
2032	84,118	56,285	62,649	178,638
2033	112,466	79,194	92,401	246,263
2034	150,374	112,976	136,281	339,486
2035	201,068	162,976	**201,000**	**468,000**



EV effect

month	Avg kwh/d
1	12.9
2	11.4
3	9.9
4	9.7
5	8.4
6	9.2
7	11.0
8	9.9
9	8.2
10	10.1
11	12.0
12	12.6



	kWh/year	kW/vehicle on	kW/vehicle on peak (unmanaged)
LDV	4202	0.60	0.74
MDV	8205	1.62	1.06
Transit Bus	113890	7.33	27.70
PHEV	2101	0.60	0.74

Vehicles already in system at end of 2024:

BEV	PHEV	Energy (GWh)	Peak (MW), managed	Peak (MW), unmanaged
3900	2600	22	3.9	4.8

	New vehicles							Energy			Peak						
Year	BEV tot	PHEV tot	MDV	HDV	Total New Vehicles	Cumlative from 2024	Total vehicles in system	GWh	Cumulative from 2024	Total Load (GWh)	Peak MW	Avg kW per car	Cumulative from 2024	Peak (MW), managed	Peak MW, unmanaged	Cumulative from 2024, unmanaged	Peak (MW), unmanaged
2024	1,620	1,080			2,700			9			1.6	0.60			2.0		
2025	2,640	1,760	100	32	4,532	1,832	8,332	19	10	32	3.0	0.67	1	5	4.3	2	7
2026	3,926	2,617	315	116	6,974	4,274	10,774	38	29	51	5.3	0.75	4	8	8.4	6	11
2027	5,609	3,739	436	199	9,983	7,283	13,783	58	49	70	7.7	0.78	6	10	12.9	11	16
2028	7,884	5,255	575	311	14,025	11,325	17,825	84	75	97	11.0	0.79	9	13	19.0	17	22
2029	11,042	7,360	729	428	19,560	16,860	23,360	117	108	129	15.3	0.78	14	18	26.3	24	29
2030	15,517	10,344	900	550	27,312	24,612	31,112	157	148	170	20.9	0.77	19	23	35.4	33	38
2031	21,957	14,638	1106	672	38,373	35,673	42,173	209	200	221	28.5	0.74	27	31	47.0	45	50
2032	32,111	20,105	1345	796	54,357	51,657	58,157	279	270	292	39.1	0.72	38	41	62.3	60	65
2033	48,147	26,978	1615	925	77,664	74,964	81,464	378	368	390	54.2	0.70	53	56	83.2	81	86
2034	73,483	35,424	1917	1060	111,883	109,183	115,683	520	511	532	75.8	0.68	74	78	112.4	110	115
2035	113,483	45,424	2,256	1,199	162,363	159,663	166,163	727	718	740	107.2	0.66	106	109	153.9	152	157

		Home	Workplace	Public L2	Public DCFC
Peak by Charging type	Managed	0.390	0.073	0.025	0.109
	Unmanaged	0.500	0.048	0.030	0.166

Energy			Peak (managed)			Peak (unmanaged)		
Res Charging (75% of LDV)	Commercial public LDV charging (25%)	Commercial MDV+HDV	Res Charging (75% of LDV)	Commercial public LDV charging	Commercial MDV+HDV	Res Charging (75% of LDV)	Commercial public LDV charging	Commercial MDV+HDV
6.8	2.3	0.0	1.1	0.6	0.0	1.4	0.7	0.0
11.1	3.7	4.5	1.7	0.9	0.4	2.2	1.1	1.0
16.5	5.5	15.8	2.6	1.4	1.4	3.3	1.6	3.6
23.6	7.9	26.2	3.6	1.9	2.2	4.7	2.3	6.0
33.1	11.0	40.2	5.1	2.7	3.2	6.6	3.2	9.2
46.4	15.5	54.8	7.2	3.8	4.3	9.2	4.5	12.6
65.2	21.7	70.1	10.1	5.4	5.5	12.9	6.3	16.2
92.3	30.8	85.6	14.3	7.6	6.7	18.3	8.9	19.8
132.9	44.3	101.7	20.4	10.8	8.0	26.1	12.7	23.5
194.2	64.7	118.6	29.3	15.6	9.4	37.6	18.3	27.3
287.4	95.8	136.4	42.5	22.5	10.9	54.5	26.6	31.4
429.2	143.1	155.1	62.0	32.9	12.5	79.5	38.8	35.6

Request IR-10:

Price Forecast (Section 4.5, p. 51)

(a) Why are electricity prices forecast to increase by 5 percent between 2026 and 2029? Why are electricity prices forecast to increase by 2 percent thereafter? Why are these values different?

Response IR-10:

(a) The five percent annual increase in electricity pricing is based upon NS Power's internal forecasting completed in Q2 2025. As NS Power has not forecast revenue requirement for future periods and there is less certainty due to the length of time to these periods, the Company used a two percent electricity price increase from 2030 onward to approximate the expected rate of inflation.

Request IR-11:

Renewable to Retail (Section 4.6, pp. 55-56)

(a) Please describe how the RTR impacts the peak load forecast.

Response IR-11:

(a) As stated on page 56 of the Report, RTR does not impact the peak forecast as NS Power is required to serve the full peak of these customers if needed.

Request IR-12:

Prevalence of AMI (Section 10.4, pp. 88-89)

(a) Please provide the percent of customers with AMI for each of the classes listed in Figure 71 on the 2024 peak day.

(b) Please provide the total number of customers in the "Rest" category.

Response IR-12:

(a) The percentage of each customer class in Figure 71 with interval data (including both AMI and older interval data collection technology) are as follows:

Class	% of Customers with AMI
Residential	96
Small General	98
General	97
Small Industrial	90
Medium Industrial	100
Rest	100
Unmetered	0

(b) The "Rest" category in Figure 71 consists of 59 customers, broken down as follows:

Class	Customer Count
Large General	20
Large Industrial	10
Large Industrial Interruptible	21
Generation Replacement & Load Following	1
Real Time Pricing	1
PHP	1
Municipal	5

Request IR-13:

IRP and ELCC (Section 10.0, p. 76)

Refer to the following statement from the Load Forecast: "On February 6, 2025, NS Power distributed to stakeholders for review and comment a draft study scope document for the next ELCC study."

(a) Please provide the draft study scope.

(b) Please describe the anticipated timeline for completion of the ELCC study.

(c) Please indicate if is expected for the 2026 Load Forecast to be able to be updated with the results of the ELCC study. If it is not anticipated to be provided in the 2026 Load Forecast, please estimate which load forecast is expected to be the first load forecast which incorporates information from the updated ELCC study.

Response IR-13:

(a) Please see Attachment 1.

(b) A timeline for a final report is not available at this time and will be developed in collaboration with the consultant completing the study.

(c) Since the timeline for the completion of the ELCC study is not yet determined it is unclear if results will be available for inclusion in the 2026 Load Forecast. However, NS Power expects the results of the study will be available for inclusion in either the 2026 or 2027 Load Forecast.

Effective Load Carrying Capability (ELCC) Study Scope Memo

February 6, 2025

In its Decision letter of May 23, 2024, regarding NS Power's 2023 Evergreen IRP Update (Matter M11307), the Board highlighted certain Synapse recommendations and stated:

> As noted by Synapse in its August 2023 comments, the battery energy storage ELCC profile is a critical input value to the modeling. This needs to be carefully re-examined in conjunction with an updated portfolio ELCC analysis, which considers the interactive effect of all four clean resources (i.e., wind, solar PV, battery energy storage, and demand response or peak load mitigation during winter peak periods). The Board sees value in further study to evaluate the incremental diversity benefit available from increased interaction among renewable resources.

NS Power affirmed its support for updating the Effective Load Carrying Capability (ELCC) study on June 27, 2024 in the 10 Year System Outlook (M11764), where it states on page 48:

> NS Power supports updating the capacity study prior to the next IRP analysis, with the focus of the update being an examination of the interactive effect of the identified clean resources (wind, solar, battery energy storage, and demand response).

Subsequently the Board asked for an update on NS Power's progress on this recommendation in NSUARB IR-02 (M11764). NS Power's response stated:

> NS Power has not started a new capacity value study, but as stated in the 2024 10-Year System Outlook report on page 48, NS Power supports updating the most recent capacity value study prior to the next IRP analysis, with the focus of the update being an examination of the interactive effect of the identified clean resources (wind, solar, battery energy storage, and demand response). As a starting point for this work, NS Power will develop a draft scope of work and project schedule to be circulated to IRP stakeholders for comment by the end of the year. This will allow stakeholders the ability to comment on the statement of work at the initial stages of development.

In accordance with this commitment, NS Power proposes the following topics as the focus of the next ELCC study for IRP stakeholder's consideration:

1. Examination of the interactive effect of the identified clean resources (wind, solar, battery energy storage, and demand response) to update the existing diversity benefits, so that the full suite of identified clean resources may be considered. To date, NS Power has studied the diversity benefits from two resource combinations: wind & batteries and solar & batteries.

2. Updated examination of the ELCC values for demand response programs using program details and measured results from NS Power's (CPP and TVP) and E1's current demand response programs.

3. Assessment of the seasonal ELCC contributions for solar, wind, hydro, and storage generation resources during the Summer period (June to September).

The rationale for selecting these topics for the new ELCC study is as follows:

- Topic one: Stakeholders requested and the Board acknowledged the value in an update to the existing diversity factors; this continues an iterative approach to enhancing and refining the ELCC values used in Nova Scotia.

- Topic two: The current ELCC values used for demand response are based on assumptions that do not represent the current DR programs being implemented in Nova Scotia. The current DR programming being delivered by NS Power and E1 did not exist at the time of the last ELCC study. As a result, generic DR programs were modeled and represented a proxy for future DR programs. There are now Nova Scotia-specific programs and measured results which can be used to develop more appropriate ELCC values for the existing programs.

  Additionally, the inclusion of this topic aligns with NS Power's commitment to stakeholders that it would review system planning related values as part of the 2024/25 Areas of Focus for the TVP Work Plan:

  > **Area of Focus 6.0 – Review of System Planning Related Values**
  > (6.1) review of system planning related values as applicable to TVP (and the technologies that deliver the load shifting such as batteries) including avoided costs and Effective Load Carrying Capability (ELCC)

- Topic three: The Summer Reliability Assessments (SRA) completed by the Northeast Power Coordinating Council (NPCC), of which NS Power is a member, and the North American Electric Reliability Corporation (NERC), would benefit from having these values. Having Summer specific values will improve the accuracy of NS Power's contribution to NPCC's SRA.

While NS Power is a Winter peaking utility, the NPCC region, which includes the Maritimes, Quebec, Ontario, New England and New York, is a Summer peaking region.

NS Power welcomes feedback from stakeholders on its proposed scope of work for the next ELCC study and requests written feedback by February 21, 2025.

Request IR-14:

DSM Potential Study (Section 4.5.1, p. 53)

Refer to the following statement from the Load Forecast. "Beyond 2025, DSM amounts are based on E1's 2019 Potential Study base case scenario. These values are all in line with past assumptions about future DSM." Please address the following:

(a) What was the most recent year of data available for the 2019 Potential Study.

(b) How did the potential study compare to actual demand side management results for the years 2021-2024? Does NS Power and/or E1 believe that the 2019 Potential Study accurately predicted the impact of DSM in that time period?

(c) Are there any expectations for creating an update to the 2019 Potential Study, or have any updates been created?

(d) Are there any key assumptions from the 2019 Potential of the 2025 Load Forecast?

Response IR-14:

(a) The study included data up to 2019.

(b) Please refer to the table below:

Year	Potential Study, Base (GWh)	Actuals (GWh)
2021	120	109
2022	133	122
2023	131	132

Year	Potential Study, Base (GWh)	Actuals (GWh)
2024	124	173

The totals over the time period in question are similar.

(c-d) As the holder of the demand side management franchise in Nova Scotia, EfficiencyOne would be in a better position to comment on any efforts to develop a new potential study or any significant deviations from the 2019 study.

Request IR-15:

Solar Generation (PV) (Section 4.4.4, pp 42-44)

(a) Please provide supporting data for the average capacity and capacity factor for the PV installations used in the forecast.

(b) Please provide the source data and calculations for the values in Figure 30.

Response IR-15:

(a) Average capacity and capacity factor are provided in the annual Net Metering Report.[1]

(b) Please see Attachment 1.

[1] M12165, Exhibit N-1, NS Power, 2024 Net Metering Report, March 27, 2025.

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PV Forecast Based on 15% growth

Values as of 2024: 11082 110

Year	Cumulative Res Installs (MW)	Cumulative Res GWh	Cumulative Comm Installs (MW)	Cumulative Comm GWh	Total Cumulative GWh	Total Cumulative Capacity (MW)	Res Install Est	Comm Install Est	Total New Installs	Total Solar Installs	Total Load (Gwh)
2025	26	27	10	11	38	36	2,898	187	3,085	14,167	148
2026	55	59	22	24	82	77	6,213	403	6,615	17,697	192
2027	88	95	36	38	133	124	10,026	651	10,676	21,758	243
2028	127	136	51	55	191	178	14,416	935	15,351	26,433	301
2029	171	184	69	75	258	241	19,462	1,263	20,724	31,806	368
2030	222	239	90	97	335	312	25,266	1,639	26,905	37,987	445
2031	281	308	114	125	433	395	31,941	2,072	34,013	45,095	543
2032	349	382	141	155	536	490	39,612	2,570	42,182	53,264	646
2033	426	467	173	189	656	599	48,438	3,142	51,579	62,661	766
2034	508	556	206	225	781	714	57,700	3,742	61,442	72,524	891
2035	593	650	240	263	913	834	67,426	4,372	71,798	82,880	1,023

Request IR-16:

Solar Impact to Peak (Section 10.2, p 85)

(a) Please provide the source data and calculations for the values in Figure 68.

Response IR-16:

(a) Please see Attachment 1.

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Previous Coincidence Factor

2022 System Load		Commercial Production at Peak						Monthly Coincidence Factor	Site1	Site2	Site3	Site4	Site5	Site6				
Month	Monthly System Peak	Site1	Site2	Site3	Site4	Site5	Site6	Max Production per Site	47	47	10	30	67	20	Avg	Adjusted tc	Adjusted Coincidence	
1	2216	0	0	0	0	0	0		0%	0%	0%	0%	0%	0%	0%	0%	0%	
2	2112	0	0	0	0	0	0		0%	0%	0%	0%	0%	0%	0%	0%	0%	
3	2024	0	0	0	2	0	0		0%	0%	0%	7%	0%	0%	1%	1%	1%	
4	1720	0	0	0	1	1	0		0%	0%	0%	3%	1%	0%	1%	1%	1%	
5	1422	45	47	3	13	31	8		96%	100%	30%	43%	46%	40%	59%	47%	10%	2022 peak was at HE15, but typically is either morning or evening, adjusted to 10%
6	1272	3	5	1	9	36	9		6%	11%	10%	30%	54%	45%	26%	21%	21%	
7	1402	28	28	2	17	26	6		60%	60%	20%	57%	39%	30%	44%	35%	35%	
8	1433	16	18	1	21	36	9		34%	38%	10%	70%	54%	45%	42%	33%	33%	
9	1336	43	43	2	14	11	5		91%	91%	20%	47%	16%	25%	49%	39%	39%	
10	1356	3	3	1	1	4	1		6%	6%	10%	3%	6%	5%	6%	5%	5%	
11	1776	0	7	4	4	5	1		0%	15%	40%	13%	7%	5%	13%	11%	0%	HE9 in 2022, all others occur in the evening
12	1973	0	0	0	0	0	0		0%	0%	0%	0%	0%	0%	0%	0%	0%	

2024 Coincidence Factor

2024 System Load		Commercial Production at Peak						Monthly Coincidence Factor	Site1	Site2	Site3	Site4	Site5	Site6			
Month	Monthly System Peak	Site1	Site2	Site3	Site4	Site5	Site6	Max Production per Site	46	47	10	30	67	20	Avg	Adjusted to 12 percent CF (commercial assumed to be 15 percent)	
1	2015	0	0	Data was n	0	0	Data was not available for 2024		0%	0%		0%	0%		0%	0%	
2	2088	0	1		1	1			0%	2%		3%	1%		2%	1%	
3	2007	0	1		2	2			0%	2%		7%	3%		3%	2%	
4	1734	0	3		1	3			0%	6%		3%	4%		4%	3%	
5	1447	18	21		5	13			39%	45%		17%	19%		30%	24%	
6	1413	20	22		15	23			43%	47%		50%	34%		44%	35%	
7	1429	12	13		7	14			26%	28%		23%	21%		24%	20%	
8	1435	15	19		10	21			33%	40%		33%	31%		34%	28%	
9	1325	3	5		7	3			7%	11%		23%	4%		11%	9%	
10	1510	3	0		2	11			7%	0%		7%	16%		7%	6%	
11	1677	0	0		0	0			0%	0%		0%	0%		0%	0%	
12	2073	0	0		0	0			0%	0%		0%	0%		0%	0%	

Average Coincidence Factor

Month	Percent	
1	0%	
2	0%	Adjusted to 0 as 2024 peak occurred in late February, typically would be earlier in winter in the evening.
3	2%	
4	2%	
5	17%	
6	28%	
7	27%	
8	31%	
9	24%	
10	5%	
11	0%	
12	0%	

Request IR-17:

New Technologies (Section 4.4.5, pp 45-46)

(a) Please provide the assumptions and calculations behind the values in Figure 33.

(b) Has NS Power considered projected cost declines of home batteries? If so, please provide the assumed cost declines.

(c) Please provide the installed battery capacity for each residential share.

(d) Please describe if there is any monetary compensation available for residential or commercial customers to export to the grid with a battery. Please describe how this compensation differs from residential PV net metering.

(e) Please confirm that the information in Figure 33 is not incorporated into the forecast and that it is a sensitivity analysis.

(f) Please describe what the Residential Share (%) variable means in Figure 33.

Response IR-17:

(a) Please see Attachment 1.

(b) No.

(c) The capacity is assumed to be 5 kW.

(d) There are no provisions for direct monetary compensation for battery exports to the grid. However, customers with a battery can export to the grid through the self-generation option

or commercial net metering, which is a banked energy credit system and not direct monetary compensation.

(e) Confirmed.

(f) The share represents a theoretical percentage of overall residential customers with a battery to provide a sensitivity around the potential magnitude of peak impact.

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*Peak:				
Scenario	**DER**	**Estimated Peak Impact**	**Units**	**Source**
Uninfluenced by NSPI	Residential BES	-	kW/unit per year Peak impact	Assumed negligible impact
Scenario (Demand Response)	**DER**	**Estimated Incremental Peak Impact (Optimistic Case)**		**Source**
Influenced by NSPI	Residential BES	(5.00)	kW/unit per year incremental peak impact versus equivalent uninfluenced scenario	SGNS (Tesla Powerwall, 5 kW)

Residential Customer Forecast Data:

Year	Customer Count Residential Total (December 31)
2035	561,353

**Best estimates based on data available as of April 12, 2021. Still many uknowns and much uncertainty with values presented.*

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Residential Customer Uptake Scenario	**50%**	**25%**	**10%**	**5%**	**50%**	**25%**	**10%**	**5%**
Year	2025	2025	2025	2025	2026	2026	2026	2026
Residential BES	(1,403,383.44)	(701,691.72)	(280,676.69)	(140,338.34)	(1,403,383.44)	(701,691.72)	(280,676.69)	(140,338.34)

**Net Impact of DR program on peak would be summation of "DER Peak Impact (kW)" value and "DER Incremental Peak Impact (DR Optimistic Case) (kW)" value.*

	Residential Uptake			
	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)

Request IR-18:

Residential Sector (Section 5.0)

(a) Please provide the source data behind the results in Figure 42.

(b) Please provide the inputs and calculations used to create Figure 43.

(c) Please provide the inputs and calculations used to create Figure 46.

Response IR-18:

(a) Please see Attachment 1.

(b) Please refer to 2025 Load Forecast Report Attachment 4 (filed electronically), tab "Residential".

(c) Please see Attachment 1.

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	2022	2023	2024	2025
Forecast Sales	4715	4830	5180	5289
Residential Weather variance	-127	-126	-104	-
Non-weather variance	263	230	-12	-
Actual Sales	4851	4934	5064	-
Weather-adjusted Sales	4978	5060	5168	5289

Month	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22
Year	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022	2022
Residential WN (kWh)	5,611,240	(11,078,660)	(24,971,916)	(15,762,297)	(3,756,692)	(4,204,344)	753,229	7,030,072	(349,445)	(20,484,367)	(22,710,145)

Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23
2022	2023	2023	2023	2023	2023	2023	2023	2023	2023	2023	2023	2023
(37,436,775)	(91,584,351)	7,346,431	(17,983,763)	(18,251,255)	574,450	2,450,464	15,546,870	(3,249,558)	2,333,081	(14,431,634)	23,770,814	(32,137,252)

Jan-24 2024	Feb-24 2024	Mar-24 2024	Apr-24 2024	May-24 2024	Jun-24 2024	Jul-24 2024	Aug-24 2024	Sep-24 2024	Oct-24 2024	Nov-24 2024	Dec-24 2024
(2,256,566)	(21,585,096)	(53,513,968)	(7,023,864)	(10,135,769)	(3,477,906)	4,485,993	(4,371,461)	(3,736,363)	848,444	(17,351,041)	14,413,639

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	Regression Model Output (GWh)	New Custo	Hybrid Adj	Solar Impa	EV Impact	RTR Sales (	DSM Total	DSM incluc	DSM additi	Total Res Sales (GWh)
2025	5268	62	0	-27	11	0	-59	-35	-24	5289
2026	5283	120	-25	-59	16	-40	-122	-72	-50	5246
2027	5299	175	-50	-95	24	-117	-186	-109	-77	5159
2028	5342	227	-75	-136	33	-117	-252	-148	-104	5170
2029	5335	275	-100	-184	46	-117	-318	-187	-131	5125
2030	5355	317	-125	-239	65	-117	-384	-226	-158	5098
2031	5398	351	-140	-308	92	-117	-451	-265	-186	5090
2032	5463	383	-156	-382	133	-117	-517	-304	-213	5111
2033	5486	413	-171	-467	194	-117	-581	-341	-240	5098
2034	5529	440	-187	-556	287	-117	-643	-378	-265	5131
2035	5570	464	-202	-650	429	-117	-703	-413	-290	5205

Request IR-19:

Renewable to Retail (Section 4.6, pp 55-56):

(a) Please explain why the total energy magnitude associated with the RTR increased compared to the 2024 forecast.

(b) Please describe how the RTR is expected to impact the peak load forecast.

Response IR-19:

(a) The RTR assumptions were updated with more recent estimates from the Licensed Retail Supplier.

(b) Please refer to Synapse IR-11.

Request IR-20:

Net System Requirement (Section 9.0).

(a) Please provide the source data and the calculations used to produce the values in Figure 57.

(b) Please provide the source data and the calculations used to produce the values in Figures 58 and 59.

Response IR-20:

Please note that Attachment 1, cited in the responses below, is an updated version of Attachment 4 from the original filing of the 2025 Load Forecast Report. This is to correct for a small error found in Attachment 4, in the following location: tab Graphs, rows 148 and 149.

(a) Please see Attachment 1, tab Graphs, cells A117 to G125.

(b) For Figure 58, please see Attachment 1, tab Graphs, cells E14 to F34. For Figure 59, please see Attachment 1, tab Graphs, cells A135 to G149.

Please note that there is a small error in Figure 59 of the Report. An updated version of Figure 59, with the corrected values highlighted, is below.

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			59
Hybrid Model Adjustment	-202	-85				-287
RTR	-117	-176	-128	135		-286
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

1

2025 Load Forecast Report Synapse IR-20 Attachment 1 has been filed electronically.

Request IR-21:

Appendix A: Forecast

(a) Please provide in electronic format the specific calculations used to create the values in Tables A1 and A2. If this information has already been provided in electronic format in one of the report attachments, please provide references to the associated attachment.

(b) Please explain the historical changes in the Interruptible Contribution to Peak values and the future year values used in the forecast.

Response IR-21:

(c) Please refer to 2025 Load Forecast Report Attachment 4 (filed electronically), tab "Sector Summary" for the calculations used to create table A1. Table A2 is derived from the information on the tab "Demand Annual Profile" tab.

(a) The table below shows a breakdown of interruptible peak forecasts compared to actuals. The forecast is expected to remain steady at 132 MW.

	Actual Interruptible Peak	Forecast for following year	1 Year Difference vs Forecast	[redacted] Forecast	[redacted] Actual	1 Year Difference without [redacted] variance
2014	83	138	55			
2015	141	139	-2			
2016	98	144	46			
2017	67	156	89			
2018	80	156	76			
2019	111	163	52			
2020	96	152	56			
2021	94	158	64			

	Actual Interruptible Peak	Forecast for following year	1 Year Difference vs Forecast	[redacted] Forecast	[redacted] Actual	1 Year Difference without [redacted] variance
2022	155	146	-9	[redacted]		
2023	58	147	89			
2024	87	132	45			

1

Request IR-22:

Sensitivity Analysis (Section 11.0 and Appendix D)

(a) Please provide in electronic format the data and calculations used to create Figures 74 and 75.

(b) Please provide the actual statistical distributions used for the sensitivity variables and how they were determined.

(c) What other variables were considered but not chosen? Please explain.

(d) Please describe if and/or how the P10/P90 probability analysis is used in decision making regarding system planning.

Response IR-22:

(a) Please see Attachment 1.

(b) All the variables used in the Monte Carlo simulation exhibit a normal distribution behavior. Generally, the mean values will be the deterministic forecast values used in the SAE models. In case of weather, they are weather normal and in the case of economics, they are the year-to-year growth rates. Please refer to Synapse IR-23, Attachment 1, "Oracle input data" tab for the inputs used.

(c) Inputs for end uses are being studied for inclusion in future P10/P90 probability models. At present, they are more difficult to model, as they have more limited data sets and present challenges in the probabilistic approach being used.

(d) The P10/P90 probability analysis is not currently being used in decision making regarding system planning.

Year	Actual_Sales	p10	p50	p90
2010	12157.7			
2011	11907.0			
2012	10475.5			
2013	11193.6			
2014	11037.4			
2015	11099.1			
2016	10809.0			
2017	10872.7			
2018	11248.9			
2019	11077.1			
2020	10722.5			
2021	10902.2			
2022	11133.9			
2023	11130.9			
2024	11326.3			
2025	11615.8	11379.8	11615.8	11859.6
2026		11170.2	11411.4	11662.6
2027		10951.8	11201.9	11457.4
2028		10974.7	11231.5	11492.1
2029		10901.6	11161.1	11430.9
2030		10863.2	11130.4	11405.7
2031		10846.6	11124.2	11405.6
2032		10878.4	11163.4	11455.5
2033		10865.6	11160.2	11462.3
2034		10922.9	11225.7	11541.5
2035		11040.3	11352.7	11676.5

Year	Actual System Peak	p10	p50	p90
2010.0	2114.2			
2011.0	2168.1			
2012.0	1881.7			
2013.0	2032.7			
2014.0	2118.2			
2015.0	2015.0			
2016.0	2111.0			
2017.0	2017.6			
2018.0	2072.5			
2019.0	2060.3			
2020.0	2050.3			
2021.0	1968.4			
2022.0	2215.7			
2023.0	2455.0			
2024.0	2088.1			
2025.0	2428.8	2307.5	2428.8	2563.9
2026.0		2327.2	2450.9	2588.1
2027.0		2337.7	2463.7	2602.6
2028.0		2358.6	2485.7	2626.9
2029.0		2374.3	2504.7	2647.5
2030.0		2393.8	2523.9	2669.5
2031.0		2421.5	2556.5	2705.5
2032.0		2453.1	2589.6	2740.4
2033.0		2495.2	2635.2	2789.5
2034.0		2546.1	2689.1	2847.1
2035.0		2609.6	2754.9	2915.7

Request IR-23:

Appendix D: Forecast Sensitivity Analysis

(a) Please provide the model outputs in electronic form.

(b) Please provide the full set of Oracle input data in electronic format so that it can be replicated.

(c) Please provide the historical data and forecasts used to develop the probability distributions for each variable used in the Monte Carlo analysis.

(d) Please provide the source data and calculations for Figure D8.

Response IR-23:

(a) Please see Attachment 1, "Figures D5, D6, D7" tab.

(b) Please see Attachment 1, "Oracle input data" tab.

(c) Please see Attachment 1, "Oracle input data" tab.

(d) The items in Figure D8 with underlying calculations are in the following IRs: Solar calculations are provided in Synapse IR-15 Attachment 1, EV calculations are provided in Synapse IR-9 Attachment 1, Battery impact calculations are provided in Synapse IR-17 Attachment 1, and P10/P90 calculations are provide in Synapse IR-22 Attachment 1.

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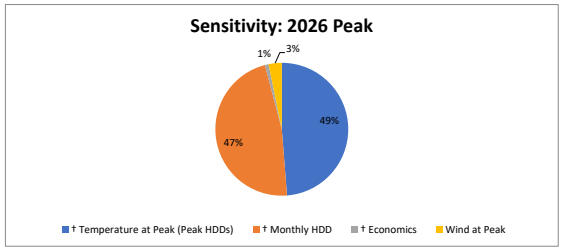
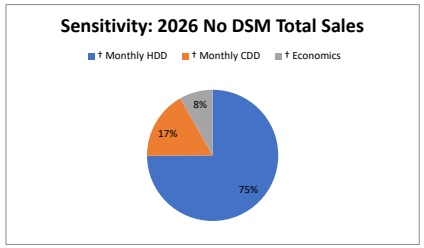
Sensitivity: 2026 Peak

Assumptions	ContributionToVariance	RankCorrelation
† Temperature at Peak (Peak HDDs)	0.487	0.59
† Monthly HDD	0.471	0.58
† Economics	0.009	0.13
Wind at Peak	0.032	0.1



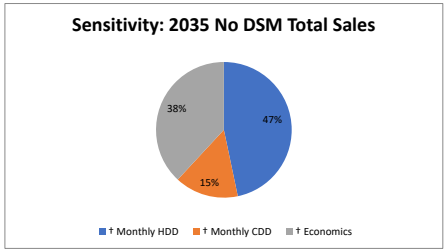
Sensitivity: 2026 No DSM Total Sales

Assumptions	ContributionToVariance	RankCorrelation
† Monthly HDD	0.749	0.84
† Monthly CDD	0.169	0.38
† Economics	0.082	0.27



Sensitivity: 2035 No DSM Total Sales

Assumptions	ContributionToVariance	RankCorrelation
† Monthly HDD	0.467	0.65
† Monthly CDD	0.152	0.36
† Economics	0.381	0.58



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Weather Normal (for forecast simulations)										Historical Monthly HDD 18 from Weather Canada (Shearwater) Data																				
Month	Month #	Monthly HDD 18	Std Dev	Monthly CDD 15	Std Dev	Peak Day AvgTemp	Std Dev	Base Wind	Std Dev	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
January	1	638.68	55.07			-15.00	2.86	18.26	8.18	757.17	552.21	643.25	632.11	737.64	634.68	632.18	601.94	686.51	651.30	686.70	646.79	615.97	639.59	650.00	631.07	590.20	649.68	509.63	624.96
February	2	585.14	45.72			-13.70	2.78	17.69	6.72	595.10	594.16	661.64	597.62	588.07	558.11	590.34	571.42	578.24	590.97	715.98	536.37	564.16	497.91	631.57	570.53	547.83	559.01	590.35	563.47
March	3	550.73	47.41			-5.74	2.78	18.52	8.08	569.13	520.53	566.32	604.54	577.91	484.27	552.49	471.59	530.39	624.49	640.05	549.23	622.03	523.09	574.41	534.16	535.03	518.44	535.38	481.08
April	4	390.39	29.88			1.53	2.23	20.18	4.93	390.80	369.51	433.38	389.98	390.23	331.50	384.61	363.71	401.88	408.62	458.88	413.35	381.84	411.01	399.31	417.49	341.39	369.10	366.18	385.09
May	5	262.56	30.29	3.58	3.57	6.12	1.72	15.89	7.26	310.08	228.34	276.39	298.25	280.34	217.85	271.38	217.63	263.80	298.76	233.39	250.33	270.35	232.93	323.41	273.42	263.73	241.96	261.44	237.43
June	6	117.06	23.58	27.40	13.10	17.68	4.65	13.89	5.60	104.66	94.93	122.53	143.84	146.48	105.85	148.27	129.90	91.48	110.46	148.39	129.87	107.60	143.76	129.88	117.35	67.18	96.65	121.28	80.82
July	7	19.76	16.58	114.80	29.01	28.01	2.86	8.28	2.55	23.23	5.85	34.85	18.73	77.69	5.58	26.71	4.75	6.30	15.04	18.20	22.73	29.94	14.95	10.16	29.09	25.96	9.79	4.92	10.74
August	8	11.96	13.54	125.31	27.02	30.73	3.71	7.78	2.60	4.66	22.69	54.00	27.71	32.94	3.48	14.12	1.00	14.15	9.27	3.11	0.67	14.49	0.11	7.56	10.03	6.16	0.00	2.13	10.85
September	9	68.36	22.53	54.68	20.75	26.12	2.55	13.09	7.21	38.73	65.02	91.11	110.85	118.29	66.51	59.70	58.05	88.30	80.70	39.47	71.15	45.78	61.17	87.20	79.48	39.90	56.81	54.58	54.45
October	10	215.82	39.78	6.44	6.25	4.07	1.90	13.93	7.01	194.67	231.07	217.72	260.79	315.83	232.12	198.17	198.23	228.00	169.45	248.16	211.51	149.29	262.16	238.31	229.40	182.81	165.12	169.14	214.42
November	11	372.22	32.82			-1.46	2.05	17.91	7.96	336.68	323.22	416.35	395.97	353.51	380.65	339.44	386.41	414.39	381.53	360.88	363.98	372.06	429.26	402.68	333.79	356.04	333.28	420.25	344.06
December	12	540.15	58.58			-8.14	2.41	20.45	7.41	552.65	513.59	659.08	557.38	572.64	488.09	482.21	515.14	615.82	484.30	462.22	612.14	581.37	626.03	562.89	455.72	527.33	486.05	494.73	553.68

Economic Factors (Actuals and Forecasts from Conference Board of Canada)												
Year	Non-Manufacturing GDP growth	Std Dev	Non-Manufacturing Employment growth	Std Dev	Manufacturing Employment Growth	Std Dev	Employment Compensation	Std Dev	HouseHolds	Std Dev	Manufacturing GDP Growth	Std Dev
2005	1.35%	1.12%	1.08%	1.39%	-6.15%	3.25%	1.94%	1.27%	-0.04%	0.77%	-0.88%	3.56%
2006	1.68%	1.12%	0.34%	1.39%	-4.42%	3.25%	1.92%	1.27%	-0.10%	0.77%	-9.41%	3.56%
2007	1.33%	1.12%	1.08%	1.39%	1.39%	3.25%	2.56%	1.27%	-0.18%	0.77%	-3.03%	3.56%
2008	1.56%	1.12%	1.46%	1.39%	-3.69%	3.25%	2.54%	1.27%	0.04%	0.77%	-0.27%	3.56%
2009	0.99%	1.12%	0.80%	1.39%	-8.44%	3.25%	1.50%	1.27%	0.24%	0.77%	-4.47%	3.56%
2010	1.71%	1.12%	0.77%	1.39%	-4.17%	3.25%	0.78%	1.27%	0.35%	0.77%	5.45%	3.56%
2011	0.35%	1.12%	0.74%	1.39%	0.05%	3.25%	-0.05%	1.27%	0.22%	0.77%	2.34%	3.56%
2012	-0.48%	1.12%	0.28%	1.39%	0.35%	3.25%	0.55%	1.27%	-0.07%	0.77%	-3.08%	3.56%
2013	0.04%	1.12%	-0.44%	1.39%	-5.70%	3.25%	2.06%	1.27%	-0.26%	0.77%	-3.49%	3.56%
2014	1.18%	1.12%	-1.02%	1.39%	-4.99%	3.25%	0.97%	1.27%	-0.23%	0.77%	-3.50%	3.56%
2015	0.87%	1.12%	-0.58%	1.39%	-4.02%	3.25%	0.88%	1.27%	-0.06%	0.77%	0.84%	3.56%
2016	1.37%	1.12%	-0.35%	1.39%	0.74%	3.25%	-1.16%	1.27%	0.48%	0.77%	0.99%	3.56%
2017	1.96%	1.12%	0.35%	1.39%	4.83%	3.25%	1.74%	1.27%	0.89%	0.77%	1.37%	3.56%
2018	1.85%	1.12%	1.11%	1.39%	6.66%	3.25%	2.57%	1.27%	1.07%	0.77%	3.62%	3.56%
2019	2.15%	1.12%	1.80%	1.39%	2.69%	3.25%	0.53%	1.27%	1.33%	0.77%	4.97%	3.56%
2020	-2.30%	1.12%	-1.84%	1.39%	0.09%	3.25%	0.58%	1.27%	1.29%	0.77%	-2.21%	3.56%
2021	4.27%	1.12%	4.80%	1.39%	1.73%	3.25%	3.65%	1.27%	1.24%	0.77%	7.59%	3.56%
2022	3.87%	1.12%	3.85%	1.39%	3.32%	3.25%	2.26%	1.27%	2.26%	0.77%	1.98%	3.56%
2023	2.38%	1.12%	3.03%	1.39%	0.62%	3.25%	4.20%	1.27%	2.81%	0.77%	0.44%	3.56%
2024	2.02%	1.12%	2.99%	1.39%	0.62%	3.25%	4.54%	1.27%	2.06%	0.77%	-0.65%	3.56%
2025	1.36%	1.12%	1.21%	1.39%	0.35%	3.25%	0.87%	1.27%	0.78%	0.77%	2.02%	3.56%
2026	1.37%	1.12%	0.09%	1.39%	0.35%	3.25%	-0.04%	1.27%	-0.12%	0.77%	2.62%	3.56%
2027	1.43%	1.12%	-0.08%	1.39%	0.48%	3.25%	0.05%	1.27%	-0.26%	0.77%	3.17%	3.56%
2028	1.39%	1.12%	0.07%	1.39%	0.49%	3.25%	0.30%	1.27%	0.00%	0.77%	3.57%	3.56%
2029	1.34%	1.12%	0.11%	1.39%	0.67%	3.25%	0.36%	1.27%	0.15%	0.77%	3.75%	3.56%
2030	1.40%	1.12%	0.12%	1.39%	0.64%	3.25%	0.50%	1.27%	0.32%	0.77%	3.74%	3.56%
2031	1.33%	1.12%	0.11%	1.39%	0.67%	3.25%	0.54%	1.27%	0.33%	0.77%	3.22%	3.56%
2032	1.33%	1.12%	0.20%	1.39%	0.79%	3.25%	0.63%	1.27%	0.30%	0.77%	3.08%	3.56%
2033	1.32%	1.12%	0.25%	1.39%	0.89%	3.25%	0.70%	1.27%	0.27%	0.77%	3.00%	3.56%
2034	1.30%	1.12%	0.29%	1.39%	0.90%	3.25%	0.75%	1.27%	0.23%	0.77%	2.96%	3.56%
2035	1.28%	1.12%	0.25%	1.39%	0.90%	3.25%	0.72%	1.27%	0.19%	0.77%	2.88%	3.56%

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Historical Monthly CDD 15 from Weather Canada (Shearwater) Data

Month	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
January																				
February																				
March																				
April																				
May	0.00	2.78	4.35	0.00	6.23	9.28	1.59	0.16	6.50	0.00	0.00	3.36	6.58	1.30	0.00	6.63	0.00	11.74	6.68	4.32
June	46.08	28.44	24.58	22.00	3.78	26.93	9.55	20.64	34.67	27.52	16.87	19.95	29.34	25.10	12.21	37.60	59.85	24.30	34.72	43.90
July	110.07	128.14	102.65	97.95	39.95	131.94	91.45	135.28	162.40	96.52	90.78	116.55	88.25	131.55	142.82	116.49	94.70	120.40	168.63	129.45
August	137.93	99.78	79.63	74.10	102.42	133.01	107.38	154.95	95.24	111.95	154.07	142.10	112.39	171.55	138.73	135.45	145.01	162.69	124.97	122.90
September	79.59	47.43	28.78	18.15	14.60	70.05	58.71	46.40	33.85	50.45	88.31	69.85	72.13	73.13	35.99	48.43	63.80	63.10	78.60	52.24
October	15.57	1.95	6.16	0.00	0.00	7.39	19.83	5.84	4.61	8.28	2.72	6.21	21.41	2.25	1.17	1.66	5.27	7.72	10.74	0.00
November																				
December																				

Request IR-24:

Appendix B: Residential Model

(a) Please provide in electronic spreadsheet format the data and the statistical model parameters and the full data and results used to produce the residential model coefficients and statistics tables.

(b) For the XHeat variable please provide the underlying factors (penetration, usage, etc.) driving the change of percentage for HP Heat.

(c) For the XCool variable please provide the underlying factors (penetration, usage, etc.) driving the change of percentage for HP Cool.

(d) For the XOther variable please provide the underlying factors (penetration, usage, etc.) driving the change of percentage for Other.

(e) Please note any changes in the model specification relative to the 2024 forecast residential model, and please further quantify the impact of any such changes in specification to the extent possible.

Response IR-24:

(a) Please refer to 2025 Load Forecast Report Attachment 5 - Residential Model, filed electronically.

(b) The HP Heat share forecast is approximately 47.5 percent in 2025 and approximately 80.5 percent in 2035; this measure is the main driver for HP Heat growth in intensity. Please refer to 2025 Load Forecast Report Attachment 1 - Residential Intensities, filed electronically, tab “Intensities” and “Shares” for details and calculations.

(c) The HP Cool share forecast in 2025 is approximately 59.4 percent, and in 2035 is forecast to be approximately 96.4 percent; this measure change is the main driver for the growth in HP Intensity. Please refer to 2025 Load Forecast Report Attachment 1 - Residential Intensities, filed electronically, tab “Intensities” and “Shares” for details and calculations.

(d) There are no significant changes for the OtherUse variable in a 10-year span. As shown in Appendix B: page 3, the drivers within OtherUse are Household Size, Price, Seasonal Use Patterns and the economic indicator for that forecast report (Employment Compensation being this year’s).

(e) The 2025 model introduces two new binary variables for September 2022 and July 2020. These variables are used to correct for large residual values in those months. Additionally, the COVID-related variable has been updated.

Request IR-25:

Appendix B: Peak Forecast

(a) Please provide in electronic spreadsheet format the data and the statistical model parameters and the full results used to produce the model coefficients and statistics tables.

(b) Please note any changes in the model specification relative to the 2024 peak forecast model, and please further quantify the impact of any such changes in specification to the extent possible.

Response IR-25:

(a) Please refer to the 2025 Load Forecast Report Attachment 10: Peak Model Inputs filed electronically. All calculations in the peak forecast are completed within Metrix ND, the forecasting software used by NS Power.

(b) The 2025 peak forecast model includes three new binary variables for June 2024, February 2018, and May 2020, to account for billing issues and improve model fit. Additionally, a first-order moving average variable has been introduced.

Request IR-26:

Residential and Commercial Heating and Heat Pumps (Section 4.4, pp 30-35)

(a) Refer to Figure 20. Please provide for all the forecast years:

(i) Total number of residential customers,

(ii) Number of customers for HP, Hybrid, Resistance, Wood, and Fossil Fuel heating systems as indicated in Figure 17.

(iii) Number of customers using heat pumps as the sole technology

(iv) Number of customers using heat pumps as primary heating with supplemental resistance heating,

(v) Number of customers using hybrid heat pumps with a breakdown of customers by the type of backup heating fuel

(vi) Number of customers using oil for primary heating,

(vii) Number of customers using natural gas for primary heating

(viii) Number of customers using propane for primary heating

(ix) Number of customers using wood for primary heating.

(b) Please indicate the number of new residential customers from 2024 through 2050 and the breakout of their space heating technology.

(c) Refer to page 33 of the report. Please provide the full scope of work for "The Path to 2030" regarding the Province's work to study the hybrid scenario. Please provide all draft study materials, if they are publicly available.

(d) Refer to Figures 20 and 21 and hybrid heating.

(i) Please provide a detailed explanation of how E3 developed its stock forecast of residential hybrid heating systems. Include all supporting evidence, such as studies, data sources, and analyses used to develop this forecast.

(ii) Please provide a detailed explanation of how E3 developed its stock forecast of commercial hybrid heating systems. Include all supporting evidence, such as studies, data sources, and analyses used to develop this forecast.

(iii) E3 results are cited, but no modeling documentation is provided. Please provide the full E3 model, report, or shared assumptions that informed the hybrid scenario.

(e) Refer to the 48 percent saturation of customers providing their heat via heat pumps in 2024 (p. 32).

(i) Is this heat pump saturation rate for residential customers only?

(ii) Please provide all the supporting evidence and calculations for this data.

(iii) The sum of the heat pump saturation rates in Figure 20 is less than 40 percent. Why did E3 scenario not reflect the latest heat pump saturation data?

(iv) Please provide NSPI's own forecast of space heating stock saturation from 2024 to 2050 for both heat pumps and electric resistance heating, corresponding to Figure 20.

(f) Refer to Figures 21 and 22. Please provide for all the forecast years:

(i) Please provide the underlying data for the commercial space heating saturation including the commercial floor area that relies on heat pumps.

(ii) Please provide a breakdown of NSPI's forecast of space heating stock saturation shown in Figure 22, including separate values for heat pumps and electric resistance heating.

(g) Refer to page 35 and Figure 23 regarding the adjustments to the energy and peak forecast values to account for hybrid heating.

(i) Please explain why hybrid heat pump systems were not explicitly modeled within the SAE framework.

(ii) Has NS Power considered incorporating hybrid systems as a separate end-use or intensity variable in the SAE model? If not, explain why.

(iii) What steps would be required to enable this integration in future forecasts?

(iv) Please explain how E3 estimated the peak load impacts of both hybrid heating systems and full heat pump systems. In your response, include the lowest temperature assumed in the analysis and the corresponding heat pump performance (coefficient of performance) at that temperature.

(v) For the hybrid heating scenario, how did E3 model switching behavior between electric and fossil backup heat? What temperature threshold, if any, was assumed for backup system use?

(vi) Please explain how NSPI estimates its HP peak impacts. In your response, include the lowest temperature assumed in the analysis and the corresponding heat pump performance (coefficient of performance) at that temperature.

(vii) Please explain the significant discrepancy between the changes in energy forecast and the changes in peak forecast in Figure 23.

(viii) Why does NSPI adopt the energy and peak forecast adjustments without making any modifications to those adjustments despite that the underlying heat pump stock forecasts are different between the two forecasts? The adjustments imply that NSPI is essentially using E3's HP analysis results. What is the role of NSPI's own heat pump energy and peak estimates?

(h) Refer to Figure 24 regarding heat pump forecast and the "2025 LFR Attachment 01 EO - Residential Intensities" workbook.

(i) Please provide a detailed explanation of how NSPI estimated the overall heating intensities. When answering this question, please indicate all the key assumptions and data sources used to develop the heating intensities.

(ii) What do "% Install Non-Elec. Heat" and "% Install Elec. Heat" in Figure 24 mean? What empirical evidence supports this assumption?

(iii) Has NS Power conducted any surveys or studies to confirm actual heating system usage post-installation for hybrid heating systems? If so, please provide the surveys or studies.

(iv) Has NS Power coordinated with EfficiencyOne to gather data on heat pump adoption through rebate programs?

(i) The report mentions the use of AMI data to meter actual consumption or savings data associated with EV (p. 39), PV (p. 43) and single-family homes (page 59).

(i) Has NS Power conducted any analysis of AMI data to verify hourly or seasonal load patterns of customers with heat pumps?

(ii) If so, please provide the methodology, sample size, and key findings from this analysis.

(iii) If not, please explain why AMI data was not used to validate assumptions about heating usage and peak contributions.

Response IR-26:

(a)

(i-ii) Please see Attachment 1, HP Stock tab for the information.

(iii) The E3 data assumes that all residential heat pump customers have a backup source.

(iv) The "Heat Pump" category in Attachment 1 assumes electric resistance as the backup source.

(v) The "Hybrid" category in Attachment 1 only assumes that the backup source is non-electric, it does not specify the fuel type.

(vi-viii) The "Fossil Fuel" category in Attachment 1 includes all fossil fuel types but does not distinguish between them. The predominant form of fossil heating in Nova Scotia is oil.

(ix) Please see the "Wood" category in Attachment 1.

(b) New residential customer heating type is not specified in the forecast, only the overall average use for single family units (14,600 kWh/year) and multi family units (4,100 kWh/year). It is assumed that the predominant heating type is heat pump with electric backup. Please refer to Figure 16 for the number of new residential customers by year.

(c) The scope of work for the Hybrid Heating study is provided below. There are no draft study materials available publicly at this time.

Hybrid Heating Study – Scope of Work

Purpose: To assess whether a hybrid heating program could ease winter peak demand as clean energy generation grows and electrification expands. This study will help inform possible program designs, gauge customer interest, and support the quantification of system-level benefits.

Key Activities

1. Jurisdictional Scan
   - Review successes and challenges from hybrid-heating programs in other cold-climate regions.
   - Document control technologies, incentive structures, administration models, and performance metrics.

2. Customer Research

- Design and deploy an online survey to estimate:
  - Heating system configurations
  - Incentive levels

3. Electric-System Modelling
   - Modelling of various scenarios to understand system level benefits such as avoided generation capacity, winter-peak reduction, cost savings, and GHG impacts.

4. Program Operationalization
   - Outline possible program governance and delivery models.

5. Reporting and Outreach
   - Compile findings and recommendations in a public report with a plain-language summary.

(d)

(i-ii) Details of the E3 analysis are provided in their report entitled "The Economics of Electrification in Nova Scotia"[1] in sections 3 and 7.

(iii) Please see Attachment 1 for the E3 data.

(e)

(i) Yes, the 48 percent is for residential.

(ii) Please refer to 2025 Load Forecast Report Attachment 01, Shares tab.

(iii) The E3 study was completed in 2022 and based on data from 2021.

[1] https://www.ethree.com/wp-content/uploads/2023/12/E3_NS-Power_Electrification-Report-1.pdf

(iv) Please refer to Figure 24 of the report.

(f)

(i) For Figure 21, please refer to Attachment 1, HP Stock tab. For Figure 22, please refer to 2025 Load Forecast Report Attachment 02, and Attachment 03, Shares tab.

(ii) The commercial forecast is not broken out into specific heating types.

(g)

(i) There is little to no historic data on hybrid heating systems, so NS Power has relied on the E3 model outputs.

(ii-iii) Yes, the current work on hybrid heating as discussed in part (c) will provide more insight on how hybrid heating might be modeled more explicitly.

(iv) Details of the E3 analysis are provided in their report entitled "The Economics of Electrification in Nova Scotia"[2] in sections 3 and 7. The scenario used in the forecast is the "Current Trends Hybrid" scenario, and the peak impact is based on E3's 1-in-2 peak temperature of -16.5 degrees Celsius. Modeled heat pump coefficients of performance are provided in Figure 7-1 of the E3 report.

(v) As outlined in section 7.2 of the E3 report, below a balance point temperature of -7 degrees Celsius both the heat pump and back up heat source are used to meet heating demand for dual fuel heat pumps.

(vi) NS Power does not estimate peak impacts of heat pumps specifically. The E3 data is used as a proxy for the impact of heat pumps to peak.

[2] https://www.ethree.com/wp-content/uploads/2023/12/E3_NS-Power_Electrification-Report-1.pdf

(vii) Please refer to NSEB IR-8.

(viii) The difference is based on the incremental increase in heat pumps between 2025 and the corresponding reference year, not the absolute number. In Attachment 1 (HP Stock tab) the difference including both HP and Hybrid amounts in shares between 2025 and 2030 is 18 percent, which is very similar to increase shown in Figure 24 (17 percent). These numbers were sufficiently close, so no adjustment was made to the E3 numbers.

(h)

(i) The year 2015 is used as the base year, and Unit Energy Consumption (UEC) values are sourced from Natural Resources Canada. To calculate the raw intensity, the UEC is multiplied by Nova Scotia's share percentage. This raw intensity is then adjusted using a factor based on actual usage per customer, resulting in the adjusted intensity for 2015.

The heating intensity for year x is estimated using the following formula:

$$Intensity_x = \frac{adjusted\ intensity_{2015} \times (\frac{share_x}{efficiency_x})}{(\frac{share_{2015}}{efficiency_{2015}})}$$

This is calculated for all the heating components (electric baseboards, heat pumps, secondary heat and furnace fans).

(ii) In Figure 24, the terms "% Install Non-Elec. Heat" and "% Install Elec. Heat" refer to the percentage of heat pumps that were installed as replacements for either non-electric (fossil fuel) or electric (baseboard) heating sources. The information on heating types is based on feedback from the contractor network.

(iii) No.

(iv) NS Power does not use data from E1 regarding heat pump installations subject to rebate programs, as it provides only partial data relevant for this analysis. Rather, NS Power gathers data directly from contractors on a regular basis to provide as complete a data set as possible.

(i)

(i-iii) NS Power has not yet conducted a dedicated analysis of AMI data specifically to verify hourly or seasonal load patterns of customers with heat pumps, as disaggregating heating load from whole-home electricity usage is complex, especially in homes with hybrid systems or multiple heating sources. While the focus on AMI data in the 2025 forecast was for EV loads and new construction, NS Power is actively working on techniques for using AMI data to better evaluate heating loads in the province.

2025 Load Forecast Report Synapse IR-26 Attachment 1 has been filed electronically.

Request IR-27:

Residential Water Heaters (WH) (Section 4.4, p. 37) and the "2025 LFR Attachment 01 EO - Residential Intensities" workbook.

(a) Please describe in detail how NSPI developed its forecast of water heating intensities from 2025 through 2035. In answering this question, please explain how the efficiency of heat pump water heaters is reflected in the intensity values.

(b) What is the data source for the efficiency values provided in columns W to AP in the "Efficiencies" tab?

(c) What does "EWHeat" in column AE in the "Efficiencies" tab represent?

(d) How does NPSI estimate peak load impacts from electric water heaters?

(e) Please provide the complete source citation for the EIA data presented in the "EIAData" tab.

Response IR-27:

(a) The year 2015 is used as the base year, and Unit Energy Consumption (UEC) values are sourced from Natural Resources Canada. To calculate the raw intensity, the UEC is multiplied by Nova Scotia's share percentage. This raw intensity is then adjusted using a factor based on actual usage per customer, resulting in the adjusted intensity for 2015.

The water heating intensity for year x is estimated using the following formula:

$$Intensity_x = \frac{adjusted\ intensity_{2015} \times (\frac{share_x}{efficiency_x})}{(\frac{share_{2015}}{efficiency_{2015}})}$$

As described on page 37 of the Report, heat pump water heaters are not incorporated into the forecast directly, but they are expected to contribute to the overall improvement in water heater efficiency over the forecast period.

(b) The data is provided by Itron.

(c) This column refers to electric water heater efficiency.

(d) NS Power does not estimate peak load impacts for individual appliances.

(e) The EIA data presented in the "EIAData" tab are obtained directly from Itron.

Request IR-28:

Demand Side Management (Section 4.5.1, pp 53-55).

(a) Please provide the source data for the DSM values used in this forecast.

(b) Please provide the DSM values used in the latest IRP.

(c) Please provide the DSM levels for all scenarios as presented in E1's 2019 Potential Study and a more recent DSM potential study if any.

(d) Please explain the basis for using E1's 2019 Potential Study base case scenario for DSM amounts beyond 2025 and how valid the use of the 2019 Potential Study is for developing NSPI's load forecast.

(e) Please provide the inputs and calculations used to create Figure 40.

(f) Please identify any changes to the forecast of Annual DSM Savings provide in Figure 40 relative to the same forecast provided in the 2024 Load Forecast Report, and please provide a narrative explanation of any such changes.

Response IR-28:

(a) As outlined in the report, the values for 2024 and 2025 are based on E1's supply plan from its 2023-2025 DSM Resource Plan Filing, approved by the NSEB July 11, 2022 (M10473). Beyond 2025, the values are based on the E1 Potential Study base case values from E1's Nova Scotia Energy Efficiency and Demand Response Potential Study for 2021-2045 filed as Exhibit N-1 in NS Power's IRP (M08929) on August 14, 2019.

(b) Please see the table below. The values for 2025 are from E1's supply agreement, while the values from 2026-2035 are from the base case of the E1 Potential Study referred to in part (a).

Year	Energy (GWh)	Demand (MW)
2025	149.5	26.4
2026	136.3	25.0
2027	137.1	25.2
2028	147.0	26.6
2029	135.1	24.5
2030	133.3	24.2
2031	130.6	23.4
2032	128.2	22.8
2033	122.3	21.6
2034	120.9	21.1
2035	116.0	19.9

(c) Please refer to E1's Nova Scotia Energy Efficiency and Demand Response Potential Study for 2021-2045 filed as Exhibit N-1 in NS Power's IRP (M08929) proceeding on August 14, 2019.

(d) The base case is aligned with current DSM levels and is used in the IRP forecast. The 2019 Potential Study is the most recent source of potential DSM in the forecast period.

(e) The data for Figure 40 can be found in Synapse IR-20 Attachment 1, tab Graphs, cells A154 – H166.

(f) No changes have been made to the forecast for Annual DSM Savings in the 2025 LFR compared to the 2024 LFR, except for the addition of a forecast value for the year 2035 and updated coefficients in the regression model.

Request IR-29:

Price Elasticity (Section 2.0, p. 12; Section 4.5, p. 52)

(a) Please identify where and to what extent NSPI has tested TVP elasticity in its Load Forecast, as required by the Board in its Decision on the 2024 Load Forecast.

(b) Please confirm that price elasticity for CPP customers are lower than that of TOU customers, and if so, please explain why.

Response IR-29:

(a) TVP elasticity is discussed in Section 4.5 of the Report. As it is not directly comparable to the elasticity used in the load forecast, testing the values directly would not provide relevant results.

(b) Confirmed. An analysis of the elasticities was not performed as part of the Load Forecast. Rather, they are discussed in the 2024 TVP evaluation report[1] in Section 3, page 20.

[1] M11823 – NS Power, TVP Pilot Program 2023/24 (Year Three) Evaluation Report, Appendix A. July 31, 2024.