Evidence Regarding Nova Scotia Power's 2026 Load Forecast

Evidence RE: M12861

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1. INTRODUCTION

Synapse Energy Economics Inc. (Synapse) presents this evidence to document its review of the *2026 Load Forecast Report* [1] (Report) of Nova Scotia Power, Inc. (NS Power), and to offer recommendations for improvements. Synapse has been engaged in the review of these forecasts for many years and recognizes NS Power's iterative improvements in the forecast.

The 2026 forecast has higher net system requirements and system peak levels compared to last year's forecast. Notably, the net system requirement now has forecast growth as compared to the forecast aggregate decline in the 2025 load forecast. The energy forecast and the peak demand forecast grow at compound annual growth rates of 0.4 percent and 1.1 percent, respectively. The principal drivers of growth in energy and peak load over the period 2026-2036 are increased EV load, electric heating, and new customer growth.

Several changes account for the higher forecast relative to 2025. NS Power reports that this year's forecast averages materially higher load than the 2025 forecast, and attributes roughly half of the increase to higher modeled heating, cooling, and other end-use intensities — especially ventilation — driven by large changes in the EIA efficiency inputs to the end-use models. Higher EV load and a lower solar generation forecast account for much of the remainder. Partially offsetting these, NS Power projects fewer heat pump installations following the wind-down of the Oil to Heat Pump Affordability (OHPA) and Home Heating System rebates.

Concerning changes in the system peak forecast, the January 25, 2026, system peak — the highest on record — prompted a revision to the peak model, which now incorporates a 24-hour lagged temperature variable to better capture multi-day cold events. This raised the near-term peak forecast by about 3.1 percent relative to 2025, a difference that narrows to 2.2 percent by 2036.

NS Power's 2026 load forecast combines forecasts produced by different methods for different rate classes. NS Power uses Statistically Adjusted End-Use (SAE) models for the residential and commercial classes; these are then combined with an econometric-based industrial forecast and customer-specific forecasts for its large customers to develop the provincial energy forecast, or Net System Requirement. Demand-side management (DSM) adjustments and other factors reflecting customer growth and specific programs are applied in building up to the system total. This composite forecasting approaching is consistent with prior year's forecasts. We discuss each of these components in this evidence.

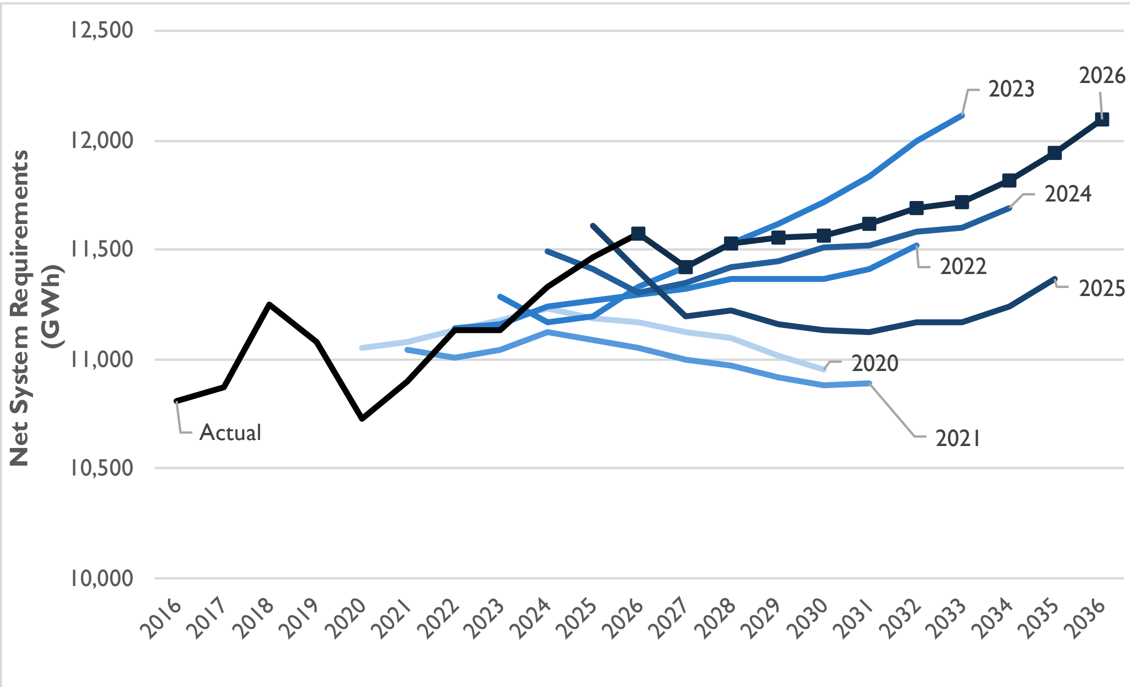
1.1. Forecast Comparisons

To begin, we compare this forecast with those of recent years. Figure 1 below shows both the actual historical energy requirements and recent forecasts. Since 2015, actual loads have been relatively flat.

[1] Nova Scotia Power, Inc. *2026 Load Forecast Report*, May 15, 2026 (2026 Load Forecast).

This year's load forecast reflects changing conditions driven by a reduction in expected electric vehicle adoption as well as an expansion of the renewable to retail (RTR) program. In total, this results in a lower forecast for 2027 and the years after compared to the projection for the same period in the 2022, 2023, and 2024 load forecasts.

Figure 1. Net system requirements



Source: Synapse from Appendix A Table A1, 2025 Load Forecast, and responses to 2024 Synapse IR-1

The current forecast predicts a 522 GWh increase in the net system requirement (NSR) from 2026 to 2036, which is equal to a 4.5 percent total increase. NS Power lays out the components of this change in Figure 58 of its Report, as shown in Table 1 below. EV load makes up the largest component of growth and is nearly double the net increase in NSR between 2026 and 2036. Additionally, model growth and new customer growth are comparably sized, but distinct in that model growth is concentrated in the commercial sector while new customer growth is concentrated in the residential sector. Offsetting these increases are rooftop solar, DSM, hybrid model adjustments, and sales through the RTR market. We discuss several of these factors in more detail in this evidence.

Table 1. Net system requirement components

	Res.	Comm.	Ind.	Other	Losses	NSR (sum)
2026 Forecast (GWh)	**5,315**	**3,165**	**2,183**	**131**	**781**	**11,575**
Model	-2	275	27	2	78	381
New Customers	350	39				389
Solar	-370	-171				-540
EV	645	373				1018
Commercial & Industrial Electrification		14	20			34

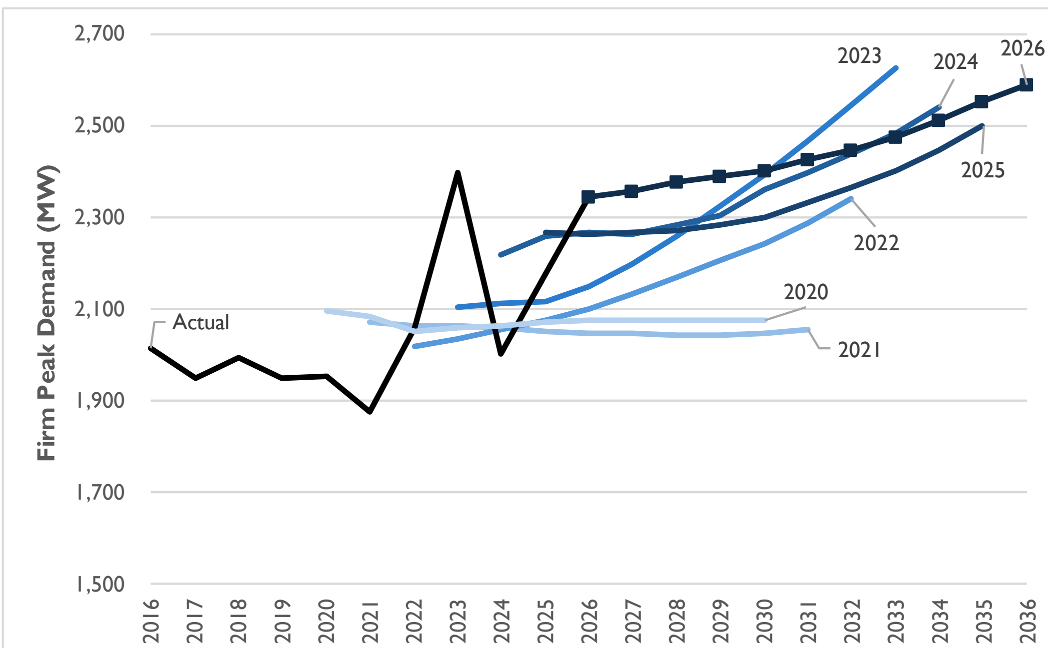
Large Customer Projects		33	186			219
Hybrid Model Adjustment	-16	-75				-91
RTR	-49	-242	-117	128		-280
DSM	-227	-198	-131	-3	-49	-607
2036 Forecast	**5,646**	**3,213**	**2,168**	**259**	**810**	**12,097**

Source: Figure 58 from 2026 Load Forecast

The historical trend for firm peak demand shows a general increase, as shown in Figure 2 below. We plotted the actual rather than the weather-normalized historical peaks to show the year-to- year variations. The 2026 firm peak demand increases 244 MW (10.4 percent) over the forecast period. Overall, this forecast increase is mostly driven by increased electrification.

The components producing this change are specified in Figures 65 of the Report (reproduced below as Table 2). The modeled values are the outputs of the SAE modeling and what follows are various adjustments to that to arrive at the firm peak.

Figure 2. Firm peak demand



Source: Synapse from Appendix A Table A2, 2025 Load Forecast and 2024 IR Response 1

Table 2. 2026 Peak contribution components (MW)

	Modeled Peak (MW)	Res Heat (MW)	EV (MW)	DR (MW)	Hybrid (MW)	C&I Elect. (MW)	Large Cust. (MW)	DSM (MW)	Firm Peak (MW)	Inter. Cust. (MW)	System Peak (MW)
2026	2,261	2	3	-8	-	0	99	-12	2,346	130	2,484
2036	2,448	14	171	-37	-6	4	110	-121	2,583	145	2,765
2036 (max non-coincident EV peak)	2,433	14	247	-37	-6	4	110	-121	2,569	145	2,841

Source: Figure 68 from 2026 Load Forecast

NS Power provides the percent error and mean absolute percent error for the firm peak forecast in Figure C5 of Appendix C. For the past 5 years, 2021 – 2025, the 1 year ahead firm peak forecast has not had a consistent trend, ranging from an over-forecast of 11.2% in 2021 to an under-forecast of 15.1% in 2023. For lead times of 5 years, there has been similar variation.

1.2. Sector Overview

The following table shows the forecast energy use by sector. Overall, industrial load is the only sector with an energy decrease. The remaining sectors have increases between 2026 and 2036. The pattern seen in Table 3 is very different from the 2025 forecast in which the municipal and other load was the only sector with a projected energy increase.

Table 3. Sector energy requirements (GWh)

	Residential	Commercial	Industrial	Municipal and Other	Losses	Total
2026	5,315	3,165	2,183	131	781	11,575
2036	5,646	3,213	2,168	259	810	12,097
Change	331	48	-15	128	17	522
Percent Change	6%	2%	-1%	98%	2%	5%

Source: Synapse from Table A1 from 2026 Load Forecast

2. Board Directives and Prior Synapse Recommendations

In its Decision concerning NS Power's 2025 forecast, in Matter 12349, dated December 19, 2025, the Board issued several directives to NS Power for its 2026 forecast.

In this Decision, the Board first directed NS Power to implement several recommendations to which NS Power had already agreed. As stated in its 2025 Reply Evidence, NSPI agreed to the :

- Evaluate whether trade tariff impacts are incremental to Conference Board of Canada forecast;
- Include impacts of hybrid heat pumps within underlying residential intensity calculations; develop the capacity to model hybrid commercial heating in future forecasts;
- A separate treatment of the intensity of heat pump water heaters;
- Incorporation of rate design and other incentives for solar-plus-batteries; and,
- Incorporation of an illustrative class-specific peak forecast.

Additionally, the Board specifically directed NS Power to:

- Monitor if adjustments are needed in the forecast to account for housing completions;
- Report further findings from the continued investigation into the unexplained variance between forecast sales and actual sales for the residential sector;
- Continue to monitor government policy with regards to encouraging or discouraging electrification; and,
- Continue comparing the Conference Board of Canada's economic forecast against those produced by Canada's five major banks, particularly for manufacturing employment; and.

The Board further *encouraged* NS Power to:

- Continue monitoring price trends in battery storage technologies.

Additionally, the Board agreed that some intervenor suggestions are more fitting for the next Integrated Resource Plan study.

3. ENERGY FORECAST

NS Power forecasts load using different methodologies for different rate classes, reflecting the distinct drivers and data available for each. For the residential and commercial classes, NS Power uses Statistically Adjusted End-Use (SAE) models. An SAE model is a hybrid of end-use and econometric methods: it embeds bottom-up projections of end-use saturation and efficiency — appliance and equipment stock and how efficiently it runs — within a regression that also responds to population, economic conditions, price, and weather. This structure lets the residential and commercial forecasts capture shifts in the end-use stock, such as growing heat pump and electric vehicle adoption, that a purely economic model would not see.

The industrial classes are forecast without end-use modeling. NS Power uses an econometric model for the Small and Medium Industrial classes, relating each class's electricity sales to projected economic indicators, and relies on customer surveys and historical data for the Large Industrial class, which is dominated by a small number of major customers forecast individually. The municipal class is treated differently again: most of these wholesale customers' energy is now supplied by third parties, so the class is largely an accounting matter rather than a modeling one, though NS Power must still carry the full municipal peak because it provides backup capacity. The residential and commercial SAE forecasts are then combined with the econometric industrial forecast, the customer-specific large-customer forecasts, and the municipal load to build up the system total.

3.1. General Updates and Major Drivers

While the forecast methodologies differ by class, a few updates and standing treatments affect the forecast broadly and are best addressed before turning to the individual sectors.

NS Power continues to source its provincial economic projections from a single 20-year forecast (now produced by Signal49 Research, the renamed Conference Board of Canada). This year, revisions to Signal49's manufacturing GDP and manufacturing employment series prompted corresponding changes to the industrial economic inputs, discussed in Section 3.4. NS Power also continues, consistent with the Board's prior direction, to benchmark the Signal49 forecast against those of Canada's major banks. As in past forecasts, the impact of potential U.S. trade tariffs is not modeled as an explicit incremental adjustment in any class; NS Power treats tariff effects as embedded in the historical data underlying the regressions. NP Power also accounts for uncertainty related to future trade policy in the P10/P90 sensitivity that is provided in the final section of the main report. Given the materiality of trade-policy uncertainty to the provincial economic outlook, this remains an area worth monitoring.

RTR migration continues to reduce forecast energy across the residential, commercial, and industrial classes as load shifts to the one licensed retail supplier, whose wind service is forecast to serve roughly 420 GWh once fully operational in 2028 (approximately 12 percent residential, 58 percent commercial, 28 percent industrial, and 2 percent unmetered). Relative to the 2025 forecast, this year reflects a delayed migration timeline and a revised distribution of that load across classes. As in prior forecasts, RTR reduces energy but not peak: NS Power remains obligated to serve the full peak of these customers and so holds the peak forecast unchanged, providing top-up energy under the Energy Balancing Service tariff.

Finally, DSM continues to be a significant load-reducing element of the forecast, subtracted from the regression results to isolate its impact. For 2026, DSM quantities are drawn from the current E1–NS Power supply agreement through 2026, E1's 2027–2031 DSM Plan Application (pending before the NSEB), and E1's 2019 Potential Study base case thereafter — all in line with past assumptions. To avoid double-counting savings already embedded in the historical regression data, NS Power continues to apply the same embedded-savings adjustment used in prior forecasts, introducing cumulative historical DSM as a load-modifying variable and letting the model determine the share already captured. We examine DSM in more detail in Section 5.4, including its implications for the peak forecast.

3.2. Residential Sector

The residential class represents about 46 percent of total load and is forecast using the SAE model described above. The model expresses residential average use as the sum of three end-use intensity terms — heating (XHeat), cooling (XCool), and other uses (XOther) — a term for embedded historical DSM savings (AvgEESavings), a COVID variable, and a set of monthly binary terms. The COVID variable is a stepped binary that explains the pandemic-era increase in residential load associated with working from home; it is set to zero over the forecast period and so does not directly affect forecast growth.

Each intensity term is the product of a use component, which captures short-term utilization, and an index component, which captures saturation and efficiency trends. Household income, household size, and electricity price are inputs to the use components; weather enters the heating and cooling terms through their degree-day inputs. Electricity price carries a −0.15 elasticity and is a modest driver relative to the others.

Table 5 presents the components of the residential forecast.

Table 4. Residential load: post regression (GWh)

	Existing Customer Average Use from Regression Model (kWh/year)	New Cust. Load	EVs	Solar	RTR	Hybrid	Res. DSM Adjust.	Res Sales	Total Res. DSM (at meter)	DSM captured by end-uses
2026	10,376	61	8	(24)	(2)	-	(19)	5,314	(36)	(17)
2036	10,367	411	653	(394)	(49)	(16)	(247)	5,645	(464)	(217)
Change to load	-0.1%	6.6%	12.1%	6.9%	0.9%	-0.3%	-4.3%	6.2%		

Source: Appendix B from 2025 Load Forecast

Relative to the 2025 forecast, growth in this year's residential forecast is flatter. In the 2025 forecast, modeled average use for existing customers rose by 5.8 percent over the forecast period, driven largely by heat pump electrification. This year, modeled average use is essentially flat, declining by 0.1 percent, from 10,376 to 10,367 kWh per customer. Over the forecast period the heating term falls by 0.3 percent and the other-use term falls by 1.2 percent, while the cooling term rises by 1.5 percent — a marked change from the 7.7 percent increase in the heating term in last year's forecast. The end-use shares of average use are broadly unchanged, at roughly 48 percent heating, 5 percent cooling, and the balance other uses, but the trajectory within each has softened.

This change reflects NS Power's reduced heat pump adoption forecast. Installations in 2025 came in about 1,000 units below the prior forecast, and with the Oil to Heat Pump Affordability program and Home Heating System Rebates wound down by the end of 2025, NS Power now forecasts roughly 4,000 fewer installations per year than in the 2025 forecast. The residential growth that remains is carried less by existing-customer electrification and more by new customers, which add 6.6 percent to load, and EVs, which add 12.1 percent, partially offset by solar, RTR, and DSM. These drivers, and the heat pump forecast in particular, are examined in Section 5.

NS Power continues to use projected housing completions as a proxy for new customer growth. In last year’s load forecast, NS Power noted that the Conference Board’s projection has systematically under-forecast housing completions by 20 percent over the period 2020-2024, and so NS Power applied a correction to formulate a more realistic projection for use in the load forecast. This year, NS Power observes that Signal49’s forecast was only 6 percent below actual additions for 2025, and that the forecast is in line with those produced by the other major banks. NS Power considers Signal49’s forecast for future additions to be “overly pessimistic” and adjusts it so that only a ten percent decrease per-year (versus the 24 percent per-year in Signal49’s forecast) is applied.

We consider NS Power’s use of housing completions to be reasonable but find that NS Power’s adjustment to Signal49’s forecast is somewhat arbitrary. NS Power should continue to monitor actual completions, and consider the forecasts of the major banks, for consideration in next year’s load forecast.

3.3. Commercial Sector

The commercial class represents about 27 percent of total load. Like the residential class, it is forecast using an SAE model, but the commercial model produces separate forecasts for its two rate classes, Small General and General Demand. The Small General forecast is based on a monthly average-use model and a separate customer forecast; the General Demand forecast is estimated on a total monthly sales basis rather than at the customer level. In both, the heating, cooling, and other-use terms are constructed from end-use intensity projections interacted with GDP and employment, real price, and monthly degree days.

Table 2 and Table 3 present the components of the two forecasts.

Table 5. Small general load: post regression (GWh)

	Load from Regression Model (GWh/year)	Model Alignment	EVs	Solar	RTR	SG. DSM Adj.	SG. Sales (with DSM)	Total SG. DSM (at meter)	DSM captured by end-uses
2026	407	13	3	(1)	(0)	(4)	418	(7)	(3)

2036	472	13	77	(18)	(7)	(27)	512	(50)	(23)
Change to load	15.6%	0.0%	17.7%	-4.0%	-1.6%	-5.5%	22.1%		

Source: Appendix B from 2025 Load Forecast

Table 6. General demand load: post regression (GWh)

	Load from Regression Model (GWh/year)	Model Alignment	RTR	Hybrid Impact	EV	Solar	GD. DSM Adj.	GD Sales (with DSM)	Total GD. DSM (at meter)	DSM captured by end-uses
2026	2,362	(13)	(10)	-	11	(7)	(25)	2,319	(46)	(21)
2036	2,611	(13)	(207)	(75)	310	(160)	(175)	2,290	(325)	(150)
Change to load	10.6%	0.0%	-8.4%	6.9%	12.7%	-6.6%	-6.4%	-1.2%		

Source: Appendix B from 2025 Load Forecast

The two classes move in opposite directions over the forecast period. Small General grows by 22.1 percent, an average of 2.0 percent per year, up from 1.5 percent per year in the 2025 forecast. That growth is driven by heating electrification and commercial EV uptake, moderated by solar, declining base load from ventilation and lighting efficiency, DSM, and RTR. General Demand, by contrast, is nearly flat, declining by 1.2 percent, as RTR migration and solar offset regression-level growth and EV load.

Across the commercial class as a whole, sales are higher throughout the forecast period than in the 2025 forecast. NS Power attributes this primarily to a lower solar generation forecast, greater EV load, and reduced DSM between 2027 and 2031.

3.4. Industrial Sector

The industrial class represents about 20 percent of total load and is projected to decline modestly over the forecast period. Unlike the residential and commercial classes, it is not forecast with end-use models. NS Power uses an econometric model for the Small and Medium Industrial classes and a combination of customer surveys and historical sales for the Large Industrial and other large-customer rate classes.

The Small Industrial class is roughly flat, with RTR migration in 2027–2028 offset by underlying economic growth. The Medium Industrial class declines by about 1.1 percent per year as load migrates to RTR. This year NS Power re-estimated the Medium model on a 10-year historic period, consistent with its other class models, improving the adjusted R^2 to 0.894 from 0.688 on the prior 19-year basis; the reduced RTR migration assumed this year is the main difference from the 2025 forecast.

The large-customer classes, which make up the majority of industrial load, are forecast from customer surveys covering a three-year horizon, with load held flat where no survey or public information is available. In the 2026 survey, 7 customers expected consumption to hold, 11 expected increases, and 12 did not respond. One customer dominates the class; a drop in its 2025 load accounts for the recent variance, with a return to normal levels expected from 2026. Load migration of about 45 GWh to RTR by 2028 is expected to be offset by a new customer and a restart at an existing customer.

The forecast assumes current major customers continue operating throughout the period, and significant changes to their operations remain a source of uncertainty.

3.5. Municipal Sector

The municipal class comprises municipal electric utilities that purchase wholesale electricity from NS Power and distribute it within their own territories. It is small and is not modeled through the SAE or econometric frameworks: most of these utilities' energy is now supplied by third parties, so the class is largely an accounting matter. Beginning partway through 2026, most municipal demand is expected to be served directly by the utilities' own wind facility, reducing bundled municipal load from about 120 GWh to 45 GWh while backup and top-up purchases rise correspondingly. Because NS Power must provide backup capacity and reserve margin, the full municipal peak remains in the Load Forecast even as the energy it serves declines.

Recommendations

NS Power should continue to monitor the impact of trade policy and consider explicitly incorporating tariff impacts into its future forecast if they are expected to have a material impact on load growth.

Concerning the adjustment to Signal49’s housing completions forecast and the associated high degree of uncertainty, NS Power should continue to monitor actual completions, consider the forecasts of the major banks, and assess whether revisions to this projection are warranted in next year’s load forecast.

4. PEAK FORECAST

NS Power forecasts the system peak by first producing a modeled peak from historical data and economic and demographic projections, then applying a series of adjustments — residential heating, EVs, demand response, hybrid heating, C&I electrification, large-customer load, and DSM — to arrive at the firm and system peak. The forecast system peak grows by an average of 1.1 percent per year from 2026 to 2036. The near-term peak forecast is about 3.1 percent higher than the 2025 Load Forecast, however, the difference narrows to roughly 2.2 percent by the end of the forecast period, as this year's lower peak growth rate — driven by reduced heating load from fewer forecast heat pump installations — partly offsets the upward near-term revision.

The most significant change this year follows the system peak of January 25, 2026, which at 2,459 MW is the highest on record. Unlike the prior record on February 4, 2023 (2,455 MW), which resulted from an extreme cold snap, the 2026 peak was reportedly driven by an extended multi-day cold period. In response, NS Power revised its peak model to include the 24-hour lagged temperature as a peak-producing weather variable, alongside the existing 12-hour lag. NS Power reports that this substantially reduces the unexplained variance in the model: applied to the 2026 peak, the unexplained component falls from 78 MW under the 2025 model to 36 MW under the revised model.

The update to the model to include 24-hour lagged temperature appears well supported by the regression statistics. We support continued use of this approach if validated in future peak load forecasts. We also encourage NS Power to continue its work on developing class-level, bottom-up approaches to peak load forecasting.

Regarding the revised peak model's forecast for 2026, while the new specification performed better than the old approach that was lacking the 24-hour lagged variable, it is notable that the 2026 appears to be the only year presented within Figure 59 in which the 24-hour lagged peak temperature was actually *lower* than the 12-hour lagged peak temperature. This does not mean that duration of cold is unimportant, but it does suggest that the influence of cold duration (and by extension, the influence of the 24-hour lagged temperature value on the peak) may interact with other variables; in other words, a simple linear specification that does not account for interactions in trying to understand the influence of temperature on peak may fall short.

Table Table 7 shows the peak forecast decomposed into component parts.

Table 7. 2026 Peak contribution components (MW)

	Modeled Peak (MW)	Res Heat Peak (MW)	EV (MW)	DR (MW)	Hybrid (MW)	C&I Elect. (MW)	Large Cust. (MW)	DSM (MW)	Firm Peak (MW)	Inter. Cust. (MW)	System Peak (MW)
2026	2,261	2	3	-8	-	0	99	-12	2,346	130	2,484
2036	2,448	14	171	-37	-6	4	110	-121	2,583	145	2,765
2035 (max non-coincident EV peak)	2,433	14	247	-37	-6	4	110	-121	2,659	145	2,841

Source: Figure 68 from 2026 Load Forecast

The table shows the build-up from the modeled peak to the system peak. The modeled peak captures the residential, commercial, small and medium industrial, and unmetered classes plus losses; the growth-program adjustments, large-customer and interruptible-customer contributions, and DSM are then layered on. The system peak rises from 2,484 MW in 2026 to 2,765 MW in 2036, an increase of 281 MW. Under the maximum non-coincident EV peak case, the 2036 system peak reaches 2,841 MW.

Recommendations

While the inclusion of the 24-hour lagged temperature variable appears to be well supported, NS Power should consider the suitability of other modeling approaches that would reflect possible interactions between lagged temperature and other variables or otherwise capture the possible non-linear impacts of long duration cold on peak.

5. DISCUSSION OF SPECIFIC END-USES AND SOLAR PV

In this section, we provide more detailed discussion of specific topics within the load forecast. We focus on heat pumps, electric vehicles, solar generation, and demand side management as these are major drivers of change in the load forecast and have been the subject of prior Synapse recommendations.

5.1. Heat Pumps

NS Power's 2026 load forecast has advanced in incorporating hybrid electric heating into its forecast for the residential sector, while continuing to rely largely on E3's prior assumptions for the commercial sector. We have certain concerns about the timing and participation rate assumptions for hybrid heating, which we discuss below.

Hybrid heating

Residential

NS Power's residential heat pump forecast distinguishes three categories of heat pump households: (1) all-electric (AE) households, with heat pumps and no backup heating; (2) non-all-electric standard (NAE Standard) households, with non-electric backup heating that are not participants in a prospective future hybrid switchover program; and (3) non-all-electric hybrid (NAE Hybrid) households, with non-electric backup heating that are participants in prospective future hybrid switchover programs.

NS Power models half of new non-all-electric systems installed beginning in 2028 as hybrid program participants.[2] NS Power states that it chose the median modeled result for achievable potential, which corresponds roughly to a 50 percent participation rate.[3] NS Power states that it used customer survey responses from the to-be-released Net Zero Atlantic Hybrid Heating Study to inform potential customer participation rates.[4]

While NS Power's methodology for estimating residential hybrid-heating potential is reasonable, its assumed participation trajectory is not when considering precedent hybrid-heating switchover and demand-management programs. We recommend two changes: first, NS Power should apply a multi-year ramp to participation among newly installed systems rather than assuming full 50 percent participation at launch. Second, NS Power should extend its hybrid curtailment assumptions to the entire stock of non-all-electric (NAE) heat-pump systems installed, using substantially limited participation rates that are more consistent with EfficiencyOne's (E1's) residential demand response experience to date.

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[2] 2026 LFR Attachment 01, "HP" tab.

[3] NS Power Response to Synapse IR-8(c)(ii).

[4] NS Power Response to Synapse IR-8(a)(ii).

For new installations, an eventual participation rate of 50 percent is plausible because NS Power could bundle curtailment enrollment with point-of-sale incentives, but assuming this level of uptake in the first year of deployment is unreasonable. NS Power should therefore model new-install participation as ramping up over several years, growing relatively quickly toward 50 percent as program delivery channels mature, rather than launching at that level.

Meanwhile, NS Power's decision to apply hybrid curtailment only to new installations is overly limiting. Many NAE heat pump systems already installed may be able to switch fuels using existing thermostat controls or minor controls upgrades. However, as effectively a retrofit measure, participation rates should instead be benchmarked to E1's residential smart thermostat program, the closest in-province analog for that acquisition channel. Assuming that each enrolled thermostat in E1's program maps to one household (a conservative assumption), E1 realized a first-year participation rate of only 0.3 percent of households in 2024, growing to 2.3 percent in 2025 and an expected 4.3 percent for the 2026 season.[5] Customers may prove somewhat more willing to enroll in a hybrid-switchover program than in a thermostat demand-response program, since switchover is consistent with a behavior many households already practice voluntarily and either maintains or improves comfort. Even so, E1's experience demonstrates that opt-in enrollment to a retrofit pathway is a gradual process with marginal annual additions. Together, these two changes would model a hybrid curtailment resource that is larger in eligible scope but more realistic in its participation trajectory.

Commercial

NS Power notes that, in response to the continued lack of provincial discussion of a commercial hybrid heating program, it delayed the modeled implementation date to 2028.[6] We caution that it may be premature to assume the same start date for commercial hybrid heating as for the residential program, for which planning is already underway. Second, while the implied participation rate (in MW of curtailment out of MW of commercial heat pump load) is not clear, the forecast includes a substantial commercial hybrid peak reduction beginning in 2028.[7] Therefore, NS Power should reassess and document whether the assumed commercial hybrid-heating trajectory represents a reasonable central forecast. At a minimum, the forecast should specify participation eligibility, adoption and ramp-rate assumptions, and an implementation date supported by commercial program or market conditions, while presenting lower and higher participation cases as sensitivities.

Efficiency assumptions and heating intensity methodology

The 2026 Load Forecast does not clearly identify which efficiency metric underlies NS Power’s heat pump assumptions. Based on our review of the forecast workpapers, we assume that NS Power uses the

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[5] EfficiencyOne (E1) 2027–2031 Demand Side Management (DSM) Resource Plan Application. M12780. Synapse analysis of E1 Response to Synapse IR-90, Attachment 1; 2026 LFR Attachment 01, “StructuralVar” tab.

[6] 2026 Load Forecast, pg. 42, lines 3-4.

[7] Synapse analysis of NS Power Response to Synapse IR-09, Attachment 1, “Adjustments” tab; NS Power Response to Synapse IR-09, Attachment 2; NS Power Response to Synapse IR-09(b)(iii).

Heating Seasonal Performance Factor (HSPF) rather than the updated HSPF2 metric, but this is not clear from the filing.[8] In future forecasts, NS Power should use HSPF2 ratings for new heat pump installations.

NS Power states that the results of the Itron Cold Climate Heat Pump Load Study “inform” the heating intensity values used in the forecast.[9] This characterization is accurate. The Itron study found that the total heating load and peak demand of all-electric (AE) heat-pump customers were comparable to those of existing all-electric customers, whereas non-all-electric (NAE) customers saw a (modeled) load increase of approximately 4,400 kWh per year and a peak increase of approximately 1.5 kW.[10]

In practice, however, NS Power derives its heat pump heating intensity through a calibration process. NS Power takes the average 2019–2021 unit energy consumption (UEC) from the NRCan dataset and applies a factor of 0.665, resulting in an assumed annual heat pump load of 4,094 kWh.[11] NS Power explains that the base-year UEC was calibrated to heat-pump-only consumption identified in the Itron study and adjusted based on actual customer usage.[12] The resulting value is generally consistent with the actual metered annual heat pump load of 4,181 kWh from the Itron study, as well as the study’s modeled value of 4,406 kWh.[13] Although the outcome appears reasonable and supporting calculations are provided in the workpapers, NS Power could describe the calibration methodology more clearly in future forecasts.

Recommendations

For hybrid heating, NS Power’s assumed participation among new installations – 50 percent of NAE systems beginning in 2028 – does not ramp gradually. NS Power should apply a more moderate ramp rate. Meanwhile, NS Power should expand modeled eligibility to include all existing NAE systems, but with substantially lower participation rates. Finally, NS Power should reassess and document whether the assumed commercial hybrid-heating trajectory represents a reasonable central forecast. At a minimum, it should apply explicit eligibility, participation, and ramp-rate assumptions and use an implementation date supported by commercial program or market conditions, while presenting lower and higher participation cases as sensitivities.

NS Power should clarify which heat pump efficiency metric (HSPF or HSPF2) underlies its forecast and, in future forecasts, it should use HSPF2 ratings for new heat pump installations. NS Power should also describe its heat-pump heating-intensity calibration more clearly, although the resulting intensity is generally consistent with the metered results from the Itron Cold Climate Heat Pump Load Study and supporting calculations are provided in the workpapers.

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[8] 2026 LFR Attachment 01, “EIAData” tab.

[9] NS Power Response to Synapse IR-7, page 5, line 3.

[10] Itron. 2022. Cold Climate Heat Pump Load Study. M09321, On-Bill Financing Final Report, Appendix A, pg. 19.

[11] 2026 LFR Attachment 01 EO, “NRCanDetail” and “Calibration” tabs.

[12] NSPI Response to Synapse IR-7(a)(iii), page 4.

[13] Itron. 2022. Cold Climate Heat Pump Load Study. M09321, On-Bill Financing Final Report, Appendix A, Table 5, page 19.

5.2. Electric Vehicles

ZEV sales forecast

NS Power assumes that zero-emission vehicle (ZEV) sales will reach 75 percent by 2035, per the federal government's implied goal of 75 percent ZEV sales by 2035 (the federal EV Availability Standard was cancelled in February 2026), with the adoption rate increasing toward the latter half of the forecast period.[14] This approach is flawed. The EV forecast was designed top-down from the federal target in 2036 and extrapolated back to the present; it does not reflect a bottom-up approach to modeling realistic deployments. It is therefore unreasonable to expect sales trends to meet the federal target purely on the basis that they are supposed to meet it. The purpose of the forecast is to estimate the load that is expected, rather than the load that is expected assuming that a federal standard is met. A target-based trajectory may be appropriate for a high case, but not for the reference-case load forecast.

We recommend that NS Power construct its reference-case EV forecast primarily in a bottom-up fashion, based on realistic inputs from a reputable source, such as the Bloomberg EV forecast or a similar forecast for the period. Under this approach, the extent to which the forecast meets the federal standard would be happenstance.

Peak charging loads

NS Power states that it is not explicitly modeling managed charging for light-duty at-home charging.[15] In doing so, NS Power is not accounting for any projected changes in managed charging penetration over the period of analysis. In future forecasts, we would like to see managed charging modeled based on participation rates, rather than combinations of actual and modeled average reductions under different scenarios.

In addition, NS Power uses a very coarse assumption that BEV and PHEV peak impacts are the same. This is problematic at two levels. First, most PHEVs cannot use DCFC. Second, assuming a driver plugs in a PHEV upon arrival at work, the vehicle would surely be done charging by the evening peak. Therefore, we recommend that NS Power remove any modeled PHEV charging from its DCFC and workplace L2 peak modeling.

Recommendations

NS Power should construct its reference-case EV forecast primarily in a bottom-up fashion based on realistic inputs from a reputable source, reserving the federal-target trajectory for a high case. NS Power should model managed charging explicitly, based on projected participation rates, rather than combinations of actual and modeled average reductions under different scenarios.

NS Power should remove any modeled PHEV charging from its DCFC and workplace L2 peak modeling it is unlikely to contribute to peak.

[14] NS Power Response to Synapse IR-11(g), 2026 Load Forecast, Figure 28, pg. 46.

[15] NS Power Response to Synapse IR-11(m).

5.3. Solar Generation

Solar generation

NS Power forecasts new PV generation separately from its SAE modeling. Solar generation can either be small-scale at the customer level, or larger utility-scale. The load forecast considers the customer-level impacts of distributed small-scale solar participating in net metering. While the number of total installations remains small in Nova Scotia, the number of new installs per year is projected to increase by a factor of two over the forecast period. This is lower compared to the 2025 forecast. The projected rate of growth in incremental residential installations was reduced to 10 percent, down from 15 percent in previous years, to reflect that the actual number of solar installations has been below forecast in recent years, combined with removal of financial incentives on the residential side. [16] NS Power further forecasts a net reduction of 710 GWh in the combined residential and commercial energy load.[17]

Because of the timing of the system peak, NS Power continues to predict no effect on the winter peak load. Due to the 2025 cyber incident, NS Power maintained the solar coincidence factors developed for the 2025 forecast using 2024 data. These factors are based on both weather patterns and the timing of system peak.[18] NS Power has stated that it intends to evaluate the solar coincidence factors in the 2027 load forecast, pending the availability of hourly data.[19]

Recommendations
NS Power should evaluate why 2025 had lower-than-forecast residential solar installations to determine whether this was an anomaly or indicative of a broader trend. The incremental distributed solar growth rate forecast should incorporate multiple years of historical data to minimize the impact of any single year. Further, NS Power should continue to evaluate and update its solar installation projections and coincidence factors for solar so they align with the latest data.

Battery storage

Battery storage is not incorporated into the load forecast. Prior load forecast reports have included illustrative estimates showing limited potential peak impacts from batteries, but further analysis is needed to evaluate the potential for peak shaving. NS Power states that costs for battery storage systems are a barrier to the adoption of these resources, relative to back-up power from gas generators. NS Power expects this to change over time as battery technology improves and costs decline.[20]

[16] NS Power response to Synapse IR-12b.

[17] 2026 Load Forecast, page 49, Figure 31.

[18] 2025 Load Forecast, page 95.

[19] NS Power response to Synapse IR-13c.

[20] 2025 Load Forecast, page 51.

Recommendations

NS Power should continue monitoring trends in behind-the-meter storage adoption, both standalone and solar-plus-storage.

5.4. DSM

Savings persistence

The cumulative savings as of the test year is the DSM input variable in NS Power's energy regression model.[21] NS Power uses a rolling 10-year accumulation period as a proxy for measure expiration, rather than applying measure-specific lives and decay or survival functions. The 10-year window is based on the lower end of an estimated 11-to-13-year average portfolio measure life.[22] A single cutoff may prematurely remove long-lived savings while retaining some short-lived savings too long. We recommend that NS Power replace the uniform 10-year window with a vintage-based persistence model using measure-category lives and decay curves.

Peak savings

NS Power assumes that the proportion of DSM savings already embedded in the energy forecast also applies to peak savings.[23] Energy and peak impacts, however, may be captured differently in the historical data and model variables, resulting in different levels of embedded savings. We recommend that NS Power estimate embedded energy and peak savings separately, rather than applying the energy-model relationship directly to peak demand. Specifically, NS Power should use cumulative DSM demand savings as the input to the peak forecast regression.

Recommendations

NS Power should replace its uniform 10-year DSM savings accumulation window with a vintage-based persistence model using measure-category lives and decay curves. NS Power should also estimate embedded energy and peak savings separately, using cumulative DSM demand savings as the input to the peak forecast regression.

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[21] 2026 Load Forecast, pages 58–59.

[22] NS Power Response to Synapse IR-15(b)–(c).

[23] NS Power Response to Synapse IR-15(a).

6. RECOMMENDATIONS

1. NS Power should continue to monitor the impact of trade policy and consider explicitly incorporating tariff impacts into its future forecast if they are expected to have a material impact on load growth.
2. Concerning the adjustment to Signal49's housing completions forecast and the associated high degree of uncertainty, NS Power should continue to monitor actual completions, consider the forecasts of the major banks, and assess whether revisions to this projection are warranted in next year's load forecast.
3. While the inclusion of the 24-hour lagged temperature variable appears to be well supported, NS Power should consider the suitability of other modeling approaches that would reflect possible interactions between lagged temperature and other variables or otherwise capture the possible non-linear impacts of long duration cold on peak.
4. For hybrid heating, NS Power’s assumed participation among new installations – 50 percent of NAE systems beginning in 2028 – does not ramp gradually. NS Power should apply a more moderate ramp rate. Meanwhile, NS Power should expand modeled eligibility to include all existing NAE systems, but with substantially lower participation rates. Finally, NS Power should reassess and document whether the assumed commercial hybrid-heating trajectory represents a reasonable central forecast. At a minimum, it should apply explicit eligibility, participation, and ramp-rate assumptions and use an implementation date supported by commercial program or market conditions, while presenting lower and higher participation cases as sensitivities.
5. NS Power should clarify which heat pump efficiency metric (HSPF or HSPF2) underlies its forecast and, in future forecasts, it should use HSPF2 ratings for new heat pump installations. NS Power should also describe its heat-pump heating-intensity calibration more clearly, although the resulting intensity is generally consistent with the metered results from the Itron Cold Climate Heat Pump Load Study and supporting calculations are provided in the workpapers.
6. NS Power should construct its reference-case EV forecast primarily in a bottom-up fashion based on realistic inputs from a reputable source, reserving the federal-target trajectory for a high case. NS Power should model managed charging explicitly, based on projected participation rates, rather than combinations of actual and modeled average reductions under different scenarios.
7. NS Power should remove any modeled PHEV charging from its DCFC and workplace L2 peak modeling because it is unlikely to contribute to peak.
8. NS Power should evaluate why 2025 had lower-than-forecast residential solar installations to determine whether this was an anomaly or indicative of a broader trend. The incremental distributed solar growth rate forecast should incorporate multiple years of historical data to minimize the impact of any single year. Further, NS Power should continue to evaluate and update its solar installation projections and coincidence factors for solar so they align with the latest data.
9. NS Power should continue monitoring trends in behind-the-meter storage adoption, both standalone and solar-plus-storage.
10. NS Power should replace its uniform 10-year DSM savings accumulation window with a vintage-based persistence model using measure-category lives and decay curves. NS Power

should also estimate embedded energy and peak savings separately, using cumulative DSM demand savings as the input to the peak forecast regression.