NIAGARA MOHAWK POWER CORPORATION

2026 to 2035 Electric Peak (MW) Forecast and Load Assessment through 2050

February 2026

Original, 02/27/2026

Electric Load Forecasting
Load Forecasting & Analytics

REVISION HISTORY & GENERAL NOTES

Revision History

Version	Date	Changes
Original	02/27/2026	- ORIGINAL

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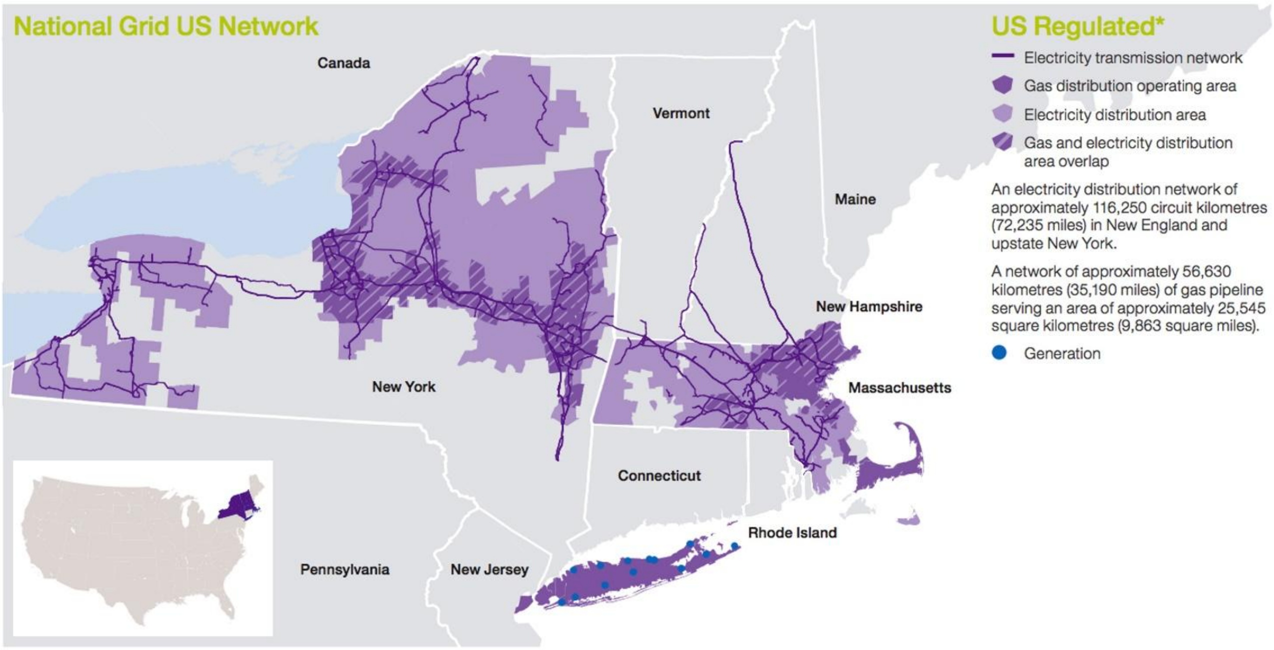
1. Acronyms

ACC-II	Advanced Clean Cars II
ACF	Advanced Clean Fleets
ACT	Advanced Clean Trucks
BEV	Battery Electric Vehicle
CAGR	Compound Annual Growth Rate
C&I	Commercial & Industrial
CLCPA	Climate Leadership Community Protection Act
DER	Distributed Energy Resource
DR	Demand Response
EE	Energy Efficiency
ES	Energy Storage
EH	Electric Heat Pump
EV	Electric Vehicle
GVW	Gross Vehicle Weight
HE	Hour-Ending
kWh	Kilowatt-Hours
LDEV	Light-duty Electric Vehicle
MW	Megawatts
MHDEV	Medium and Heavy-Duty Electric Vehicle
NE: NY	New Efficiency: New York
NIMO	Niagara Mohawk Power Company
NREL	National Renewable Energy Laboratory
NYISO	New York Independent System Operator
PV	Solar Photovoltaic
SEP	New York State Energy Plan
SME	Subject Matter Expert
PHEV	Plug-in hybrid electric vehicle
VIO	Vehicles in Operation
VMT	Vehicle Miles Traveled
ZEV	Zero-emissions vehicle
ZONE A	Western Region
ZONE B	Genesee Region
ZONE C	Central Region
ZONE D	North Region
ZONE E	Mohawk Valley Region
ZONE F	Eastern Region

2. Executive Summary

National Grid's US electric system is comprised of three companies serving over 3 million customers in Massachusetts and upstate New York. The three electric companies are: Massachusetts Electric Company and Nantucket Electric Company, serving close to 1.4 million customers in Massachusetts; and Niagara Mohawk Power Corporation, serving over 1.7 million customers in upstate New York. Figure 1[1] shows the Company's service territory in the U.S.



*Access to electricity and gas transmission and distribution assets on property owned by others is controlled through various agreements.

Source: National Grid

Figure 1: National Grid U.S. Service Territory

Key Takeaways

- 2025 summer peak loads for NIMO remained below its historical highs, despite occurring under hotter-than-normal weather conditions. Weather-adjusted peaks were lower by about 4% under normal weather conditions, highlighting the influence of hot summer weather conditions on observed loads.

- Under the Base DER scenario, the 10-year 90th peak load Compounded Annual Growth Rate (CAGR) is projected at 1.2%. Baseload demand expects minor to almost flat growth in line with economic and demographic trends in Upstate New York. Demand-side management and distributed generation resources remain the most impactful load modifiers in reducing peak load relative to what it would otherwise be, given their cumulative amount. As peak demand gradually shifts later into the evening and, over the longer term, towards winter, their direct influence on the hour of observed system peak may change, even though they continue to provide substantial load-reducing benefits. In the outer years of the 10-year horizon,

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[1] National Grid also serves gas customers in these same states which are also shown on this map.

transportation and heating electrification become the dominant drivers of peak load growth. NIMO system is projected to switch from summer-peaking to winter-peaking in 2034/2035 winter.

- The Base DER scenario models company plan, market trend, state policies, and subject-matter-experts inputs whenever available and models a trajectory towards meeting the State's climate goals in the long term. Assessments under alternative scenarios are also provided to account for uncertainties.
- Uncertainty remains the most significant risk, shaped by policy developments, program design, funding availability, technology evolution, and market dynamic. To reflect these uncertainties, load assessments are evaluated across thousands of scenarios, ensuring a robust range of possible outcomes.

The remainder of this report presents the 10-year peak load forecasts and long-term load assessment through 2050, along with a detailed discussion of the methodologies, assumptions, and drivers underlying the analysis.

3. Forecast Summary

Peak electric load is the highest electric demand of a year. Forecasting peak electric load is important to the Company's capital planning process because it enables the Company to assess the reliability of its electric infrastructure, enables timely procurement and installation of required facilities, and provides system planning with information to prioritize and focus their efforts.

The Company forecasts its 10-year ahead peak electric load, the six NYISO zones that make up its service territory in upstate New York, as well as close to 2,000 distribution feeders. Each of these forecasts is the independent (or non-coincident) peak for that level. The independent peak is the demand that each of the hierarchy level experiences, regardless of whether the demand is also the same day and time as the Company's peak. Beyond the 10-year forecast, a peak load assessment showing policy-based scenario outcomes is provided through the year 2050. The six NYISO zonal forecasts are:

- Western Region: comprised of the Company's service territory in NYISO Load Zone A which includes the Buffalo area.
- Genesee Region: comprised of the Company's service territory in NYISO Load Zone B which includes several of the counties near the city of Rochester, but does not include, the city of Rochester.
- Central Region: comprised of the portion of NYISO Load Zone C served by the company which includes the Syracuse area.
- North Region: comprised of the portions of NYISO Load Zone D served by the company which includes Massena area and the northern most areas of the state near the Canadian border.
- Mohawk Valley Region: comprised of the portions of NYISO Load Zone E served by the company which includes the Utica, Watertown, and Adirondack areas.

- Eastern Region: comprised of the portion of the NYISO Load Zone F served by the company, which includes the Albany, Saratoga and Glen Falls areas.

The Company's[2] peak demand in 2025 was 6,629 MW[3], on Wednesday, July 24 at hour-ending 20. This 2025 peak was 7.3% below the company's all-time high of 7,149 MW reached on Thursday, July 21, 2011.

This summer's weather for NIMO's peak[4] was considered warmer than average (or 'normal'). The peak weather fell in the 75th percentile of peak weather in the past over 20 years. This means that 75% of summers had peak weather that was cooler and 25% of summers had peak weather that was warmer. This year's peak is considered about 273 MW higher than the peak the company would have experienced under normal weather conditions. Thus, on a weather adjusted "normal" basis this year's peak was estimated to be 6,356 MW. Under the 90th weather condition, the Company's summer peak was estimated to be 6,856 MW.

Figure 2 shows the historical annual peak (solid blue line with marker) and the weather-adjusted historical (till year 2025) and the projected (post-2025) 50th (solid green line), 90th (solid blue line) and 95th (solid orange line) annual peak. The vertical dashed line marks the end of the 10-year forecast horizon. The Company's 90th peak load, used for planning purposes, has a projected Compound Annual Growth Rate (CAGR) of 1.2% for the 10-year load forecast horizon (from 2025 to 2035). Figure 3 presents the 90th annual peak load by components in year 2035. The system remains summer peaking through the year 2034 and the peak hour is expected to shift from late afternoon/early evening to later in the evening. During these later hours, EV charging demand increases, and PV savings become less or unavailable. Although the impacts from solar PV diminish at the later time, overall, it does still help lower the peak load. Figure 4 presents the summer peak load would be about 520 MW or 7% higher at the end of the 10-year forecast horizon if there were no PV and energy storage. Starting in year 2035, NIMO is expected to become a winter peaking system. This change is mainly driven by the increasing beneficial electrification in the transportation and space heating sectors. Between 2025 and 2050, the Company's 90th peak load has a projected CAGR of 3.3%. Figure 5 presents the Company's 90th percentile annual peak load by components for year 2050. In 2050, the system is projected to have its annual peak in the night of the winter season, where solar PV is unavailable and EV charging load and electric heat pump (EH) load is high. There is currently no Company-run demand response program for winter thus the DR category shows a zero-load impact.

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[2] Company refers to Niagara Mohawk for the remainder of this report.

[3] Meter Data Service's system level PRELIMINARY and subject to change.

[4] Peaks days, times and weather can vary across the zones which do not always match the same as for the Company.

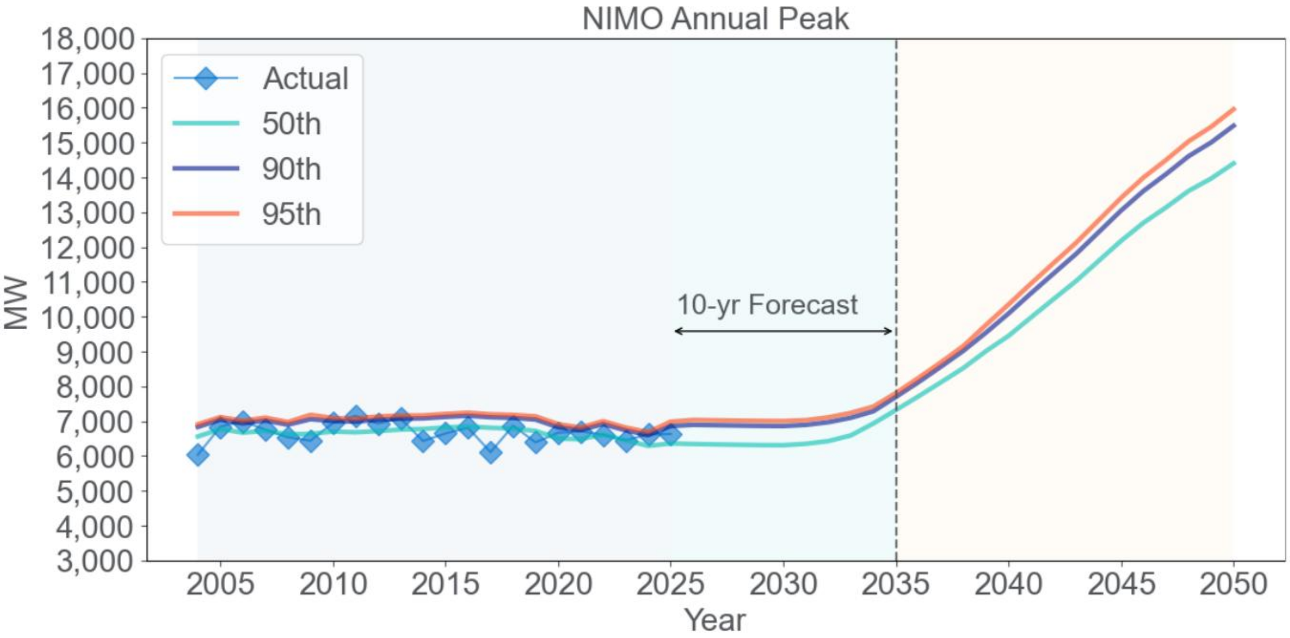

Figure 2: NIMO Historical (actual & weather-adjusted) and Projected Annual Peak Load

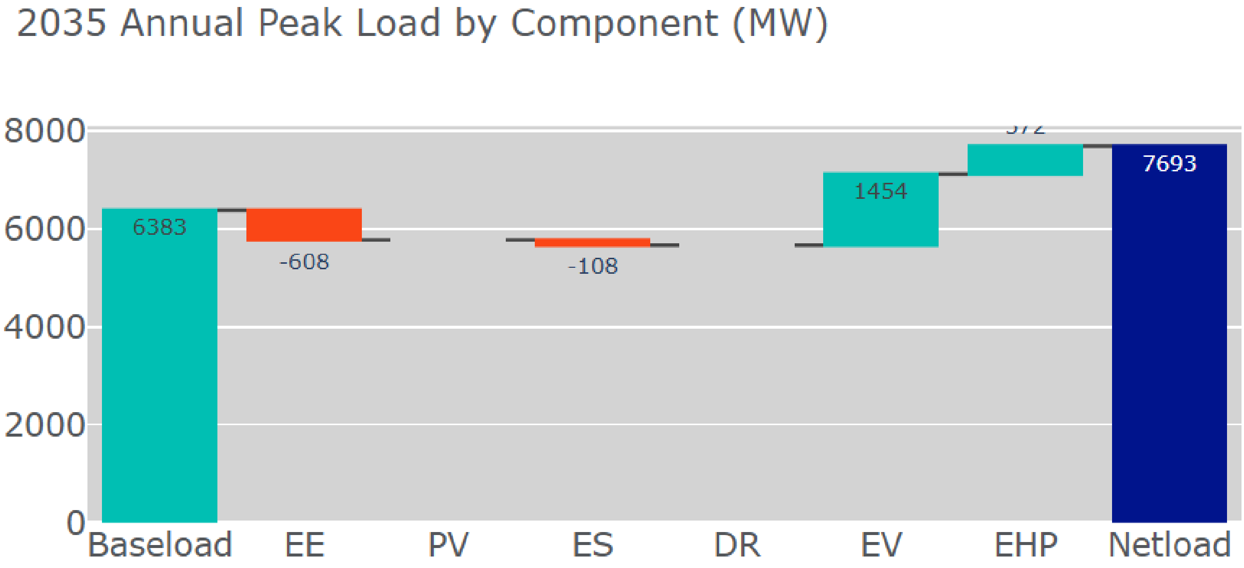

Figure 3: 90th Annual Peak Load by Components (2035)

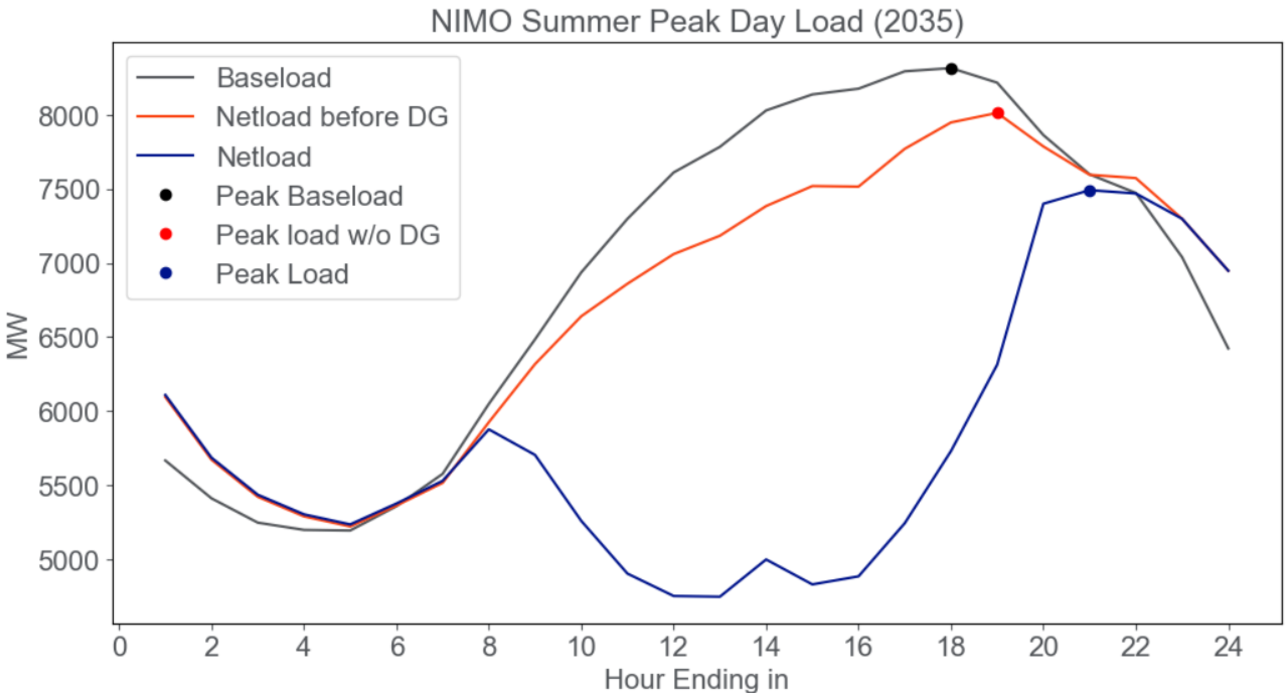

Figure 4: NIMO 90th Summer Peak Load without PV and Storage (2035)

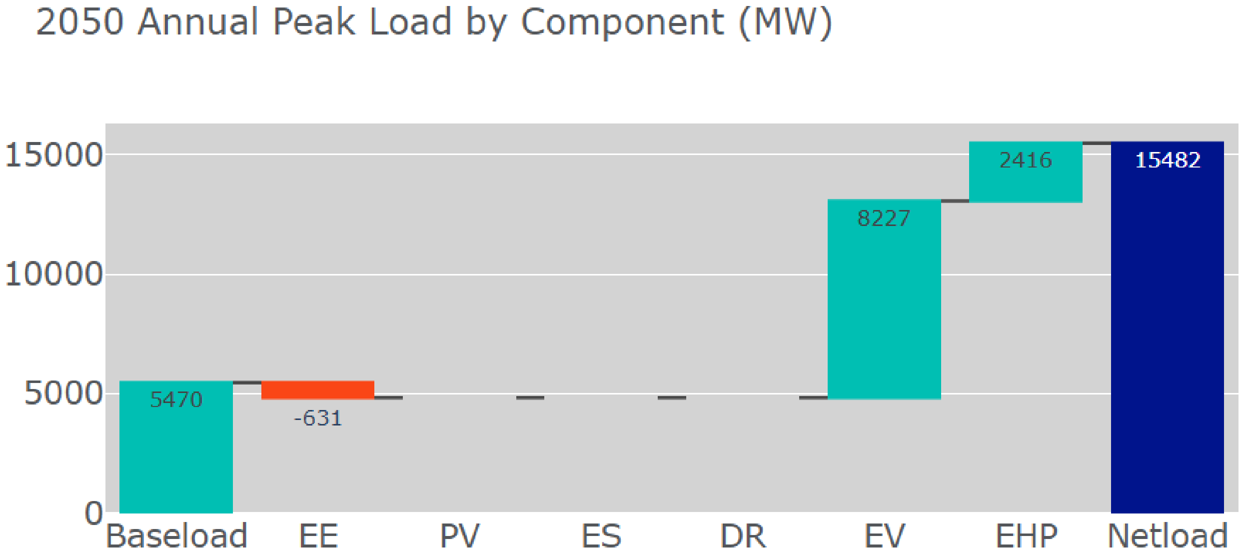

Figure 5: 90th Annual Peak Load by Components (2050)

4. Forecast Methodology

The peak load forecast consists of two major components: (1) Baseload and (2) Impacts of Distributed Energy Resources (DER) including energy efficiency (EE), solar PV (PV), energy storage (ES), electric vehicles (EV), electric heat pumps (EH), and demand response (DR). The Baseload is defined as the demand before the impacts from DERs. The forecasted Baseload is then adjusted for the cumulative impacts from DERs. Section 3.1 discusses the methodologies of developing Baseload forecasts and Section 3.2 discusses estimating DER impacts. In Section 4, the integrated results (i.e., the netload) are presented.

4.1. Baseload

4.1.1. Company and ISO Zonal Level Baseload

The underlying customer demand, or Baseload (defined as the electric demand before impacts from DERs), is impacted by weather and customer behavior. When the weather is hot in the summer or cold in the winter, the demand is usually higher. Customer behavior follows certain established patterns. For example, the demand is, on average, higher during weekdays when people go to work or school, and lower during weekends. In the long-term, macro-economic and demographic changes also drive the underlying demand change. For example, a growing population brings more demand. Regression-based predictive models that consider weather, customer behavior patterns and macro-economic and demographic changes are developed to predict the Baseload.

Due to the poor predictability of weather, it is unrealistic to use the weather forecast in the predictive model for long-term load forecasting. Traditionally, average temperature profiles of previous few decades' weather history are often used as the weather profile to generate a single-valued long-term peak load forecast. However, an average profile may understate the peaks and due to the nonlinear relationship between the load and weather, such a profile may not offer sufficient coverage on possible peak-creating scenarios. Instead, the Company takes a probabilistic approach by using peak-creating weather scenarios developed from decades of historical weather[5]. In details, the method selects hot summer days and cold winter days from each of the historical weather year and assumes each of the selected historical weather condition has an equal possibility to occur again in a future year thus to trigger high demand. The method also assumes each of the selected weather condition can occur on any day of a week in summer and winter months thus to capture different customer behaviors. Feeding these scenarios into the predictive model yields a distribution of possible peak load. The desirable quantiles (e.g., 50th, 90th, 95th) are then derived from the distribution of the predicted load to yield the corresponding Baseload forecast. In contrast to the traditional single-valued or point forecast that gives a deterministic forecast about the future load, this probabilistic forecast estimates the respective probabilities for all the possible future outcomes thus offers insights on the uncertainties.

Economic and demographic changes drive the long-term customer energy needs. The Company looks at the historical trends and relationships between historical energy and macro-economic, demographic and / or energy price variables in econometric models to develop the future energy outlook. The econometric model is developed separately for residential, commercial, and industrial customer classes. The future energy outlook is then used in the predictive model for peak load forecasting. This method

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[5] 30 years of hourly weather history was used in this forecast.

is employed based on the fundamental understanding that the impacts and relationships of the primary economic indicators are already reflected within the econometric models. Leveraging the energy outlook allows the peak-demand models to capture the economic effects as well as other energy dynamics that might not be captured through direct inclusion of economic variables alone. By focusing on annual energy as a key explanatory variable, the peak process can be tailored to include the most pertinent variables for each revenue class (i.e., residential, commercial, and industrial), enhancing the accuracy and relevancy of the forecast. For example, number of households is generally a good indicator of residential customer growth, while manufacturing employment is usually a good indicator of the load growth in the industrial sector. Overall, this approach is supposed to more specifically captures the overall economic and demographic changes in the area. Section 3.1.2 offers insights on the macro-economic and demographic outlook from Moody's.

Figure 6 presents the Company's seasonal Baseload growth. For the 10-year forecast horizon (between 2025 and 2035), the Company's summer peak Baseload expects a CAGR of 0.1%. Between 2025 and 2050, the Baseload expects a CAGR of 0.06%. The Company expects gentle near-term growth and smaller growth in the long term driven by Moody's down-trending outlook on demography in upstate New York. Section 3.1.2 discusses Moody's economic and demographic outlook. Figure 7 presents the Company's 90th Baseload profile on the summer peak day for selected years. During the summer, the Baseload peaks in the early afternoon corresponding to hotter weather conditions and more activity in the daytime and trends lower when the weather is normally cooler in the early morning and during the night when there is also less active electric usage. Figure 8 presents the 90th Baseload profile on the winter peak day for selected years. During the winter, the Baseload profile has double peaks: one in the morning and a second in the early evening. These are driven by colder weather conditions in the early morning hours when people are rising and after sunset when people arrive at home, switching on lighting, heating, cooking, etc.

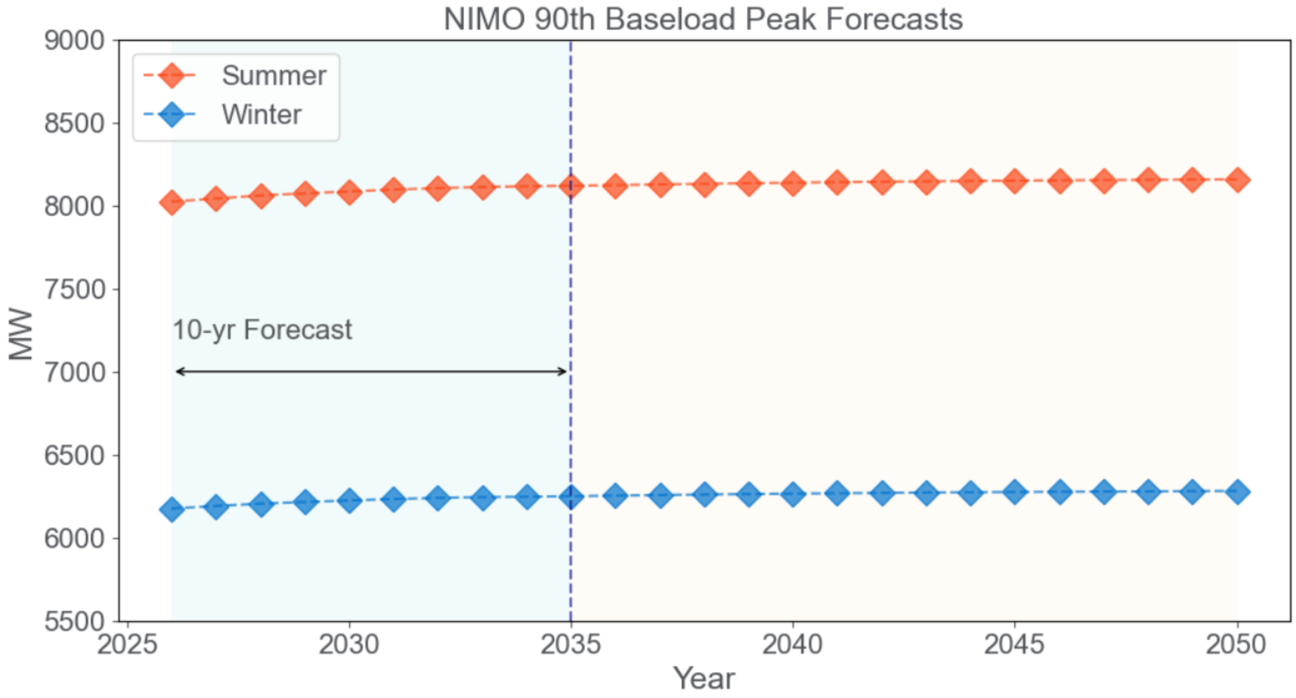

Figure 6: Summer and Winter 90th Baseload Peak[6] (2025-2050)

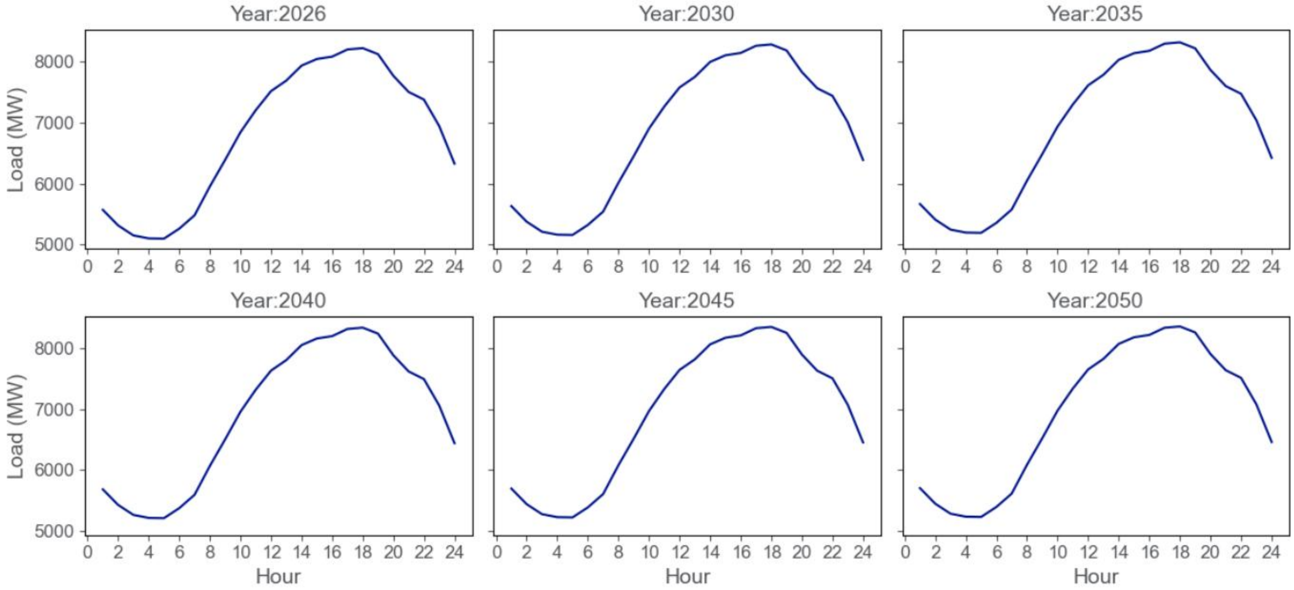

Figure 7: Summer Peak Day 90th Baseload Profiles

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[6] Baseload peak means the highest point of Baseload which is usually not the same as the Baseload at the netload peak time.

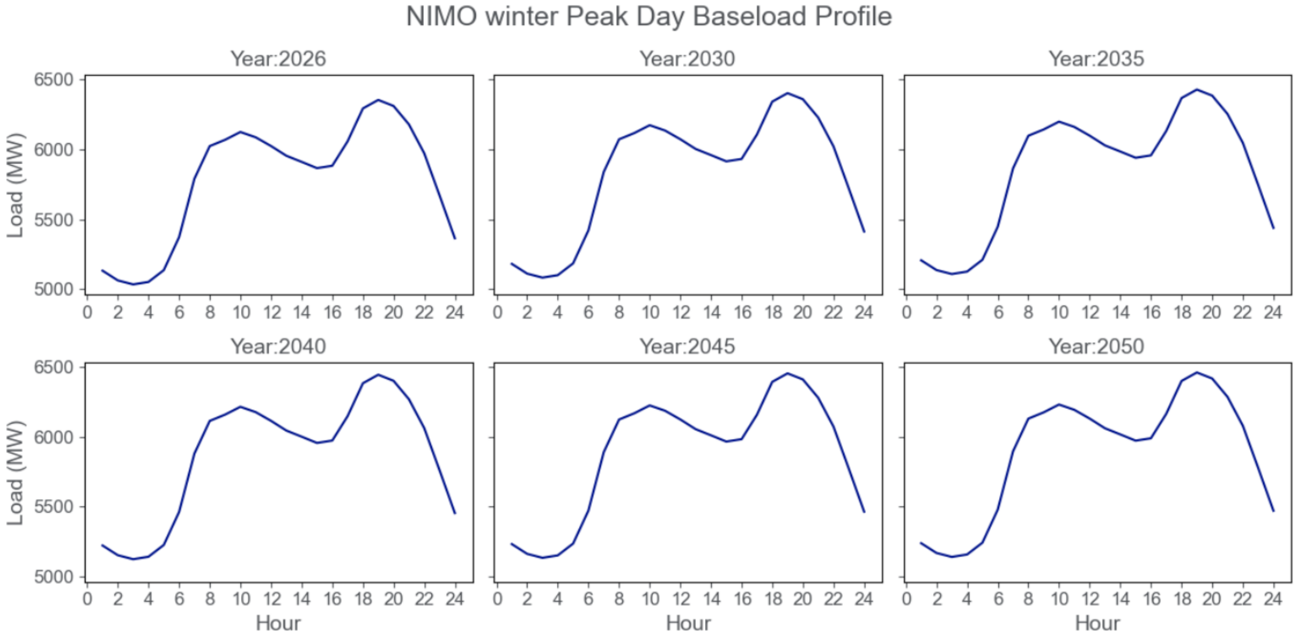

Figure 8: Winter Peak Day 90th Baseload Profiles

4.1.2. Economy

Historical and forecast economic and demographic variables are obtained from Moody's Analytics[7]. Moody's provides economic forecasts at the U.S., state, metro, and county levels. The Company aligns these areas with its service territories to obtain economic forecast for each operating company that can be leveraged in predicting energy consumption and deliveries. Under its baseline forecast, Moody's makes several major national assumptions:

- The Federal reserve is expected to cut the policy rate twice, in September and December from its current target of 4.25%-4.5% (ended up cutting 3 times)
- Tariff and immigration policies result in slower economy
- U.S. effective tariff rate increased slightly in the end of 2025 and first quarter of 2026, as a result of 50% tariff levied on goods from India due to its imports of Russian oil and an expansion of products subject to aluminum and steel tariffs
- Labor market concerns as the job market stagnated, expected average monthly job gains of 20,000 for the next several quarters
- Real GDP outlook has growth of 1.5% in 2026 and 1.8% in 2027

The long-term fate of any region is closely tied to demographics. The factors influencing where people decide to move and settle play a crucial role in determining the influx of talent and manpower necessary for a vibrant economy. Migratory patterns on a national scale will continue to favor the "Sunbelt" and

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[7] Moody's September 2025 release

states that can offer more attractive and affordable real estate to new generations that are eager to settle down into suburban life. For New York, domestic migration is likely to continue weighing on population trends, while the Trump administration's immigration crackdown raises the risk that total net migration turns negative again in 2025, after a brief return to positive inflows in 2024. While a few key industries, such as healthcare, have kept the labor market afloat throughout 2025, New York's surprise resiliency is expected to stall in the near term in line with an expected broader national slowdown, with growth following the traditional business cycle as the U.S. recovers. The state's long-term prospects remain muted from persistently high costs, business and otherwise, and continued net out-migration. Upside risks relevant to energy demand include planned semiconductor investment and a potential easing of labor supply constraints should immigration-related frictions diminish [8]

Key economic drivers used for NIMO include:

- Number of households for the customer count forecasts of the residential sector
    - Growth in the number of households is indicative of the overall energy growth in an operating company's service territory as a growing number of households is strongly correlated with a greater number of residential customers. In a similar capacity, greater household growth is also indicative of greater growth in the number of commercial customers as more commercial customers are needed to be able to provide goods and services to the larger pool of residential customers, which would have a positive relationship with annual energy.

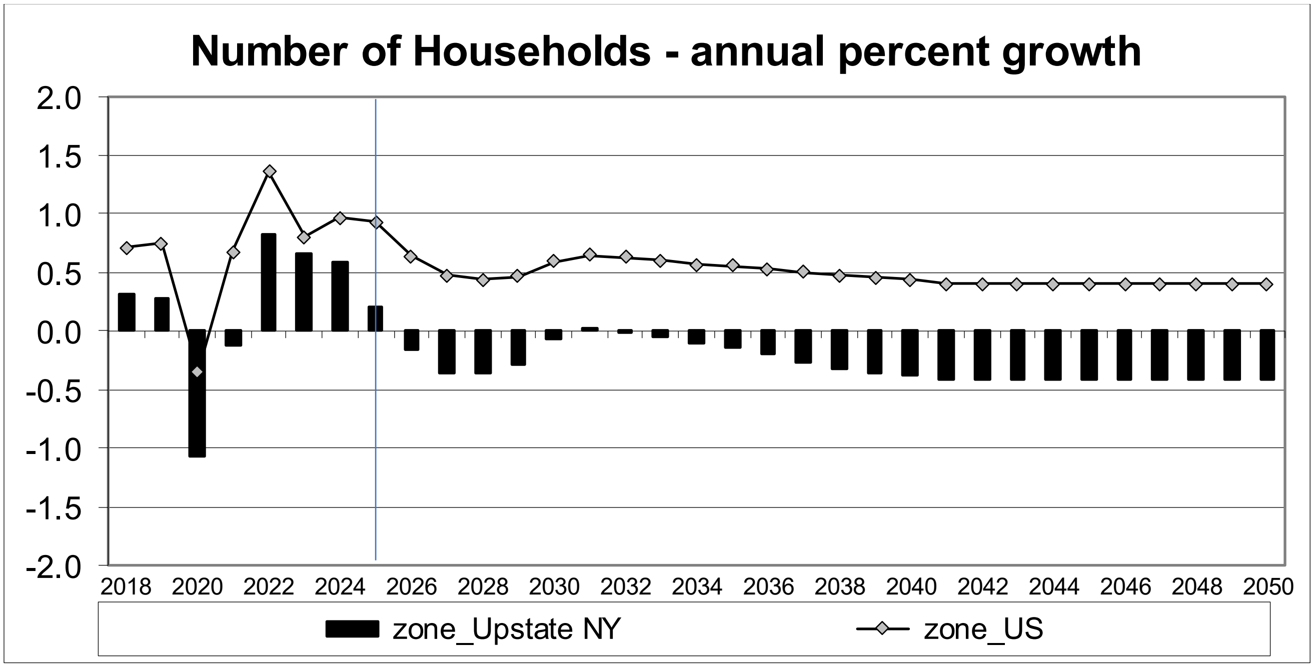

Figure 9: Annual Growth Rates of US and NY Household Numbers

- Income per capita for the usage per customer forecasts for the residential sector.

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[8] Kamins, Adam. "Précis State: New York." *Moody's Analytics, September 2025*, https://www.economy.com/. Accessed 9 Jan. 2026.

  - An increase in income per capita exerts a positive influence on residential electric usage. As income per capita rises, households generally have more disposable income to spend on goods and services. This increase in purchasing power often leads to higher consumption of energy-intensive goods and services.

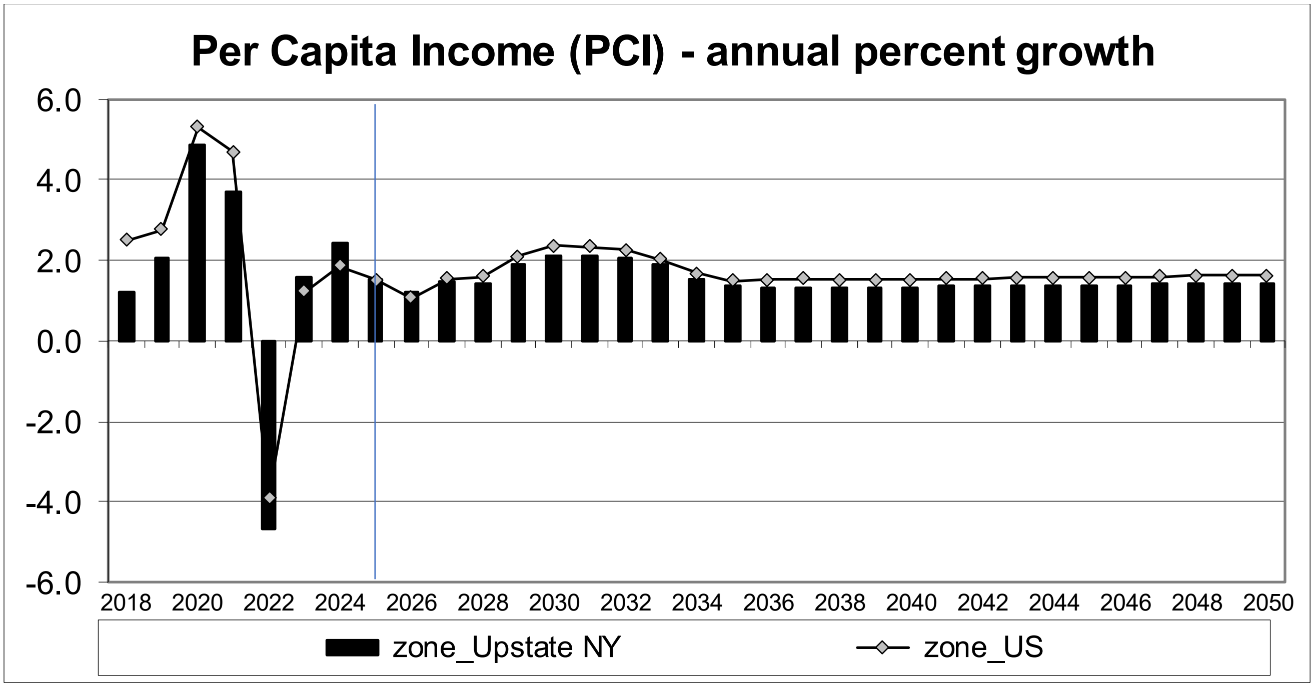

Figure 10: Annual Growth Rates of US and NY PCI

- Gross state product for the customer count forecasts of the commercial sector.
  - GSP (and GDP) can provide an overall indication of the strength of the economy; all else equal, a greater value of the goods and services that are produced suggests a greater level of economic activity, and that greater activity typically translates into greater incomes for households and businesses that can be further injected into the economy in a positive feedback loop.

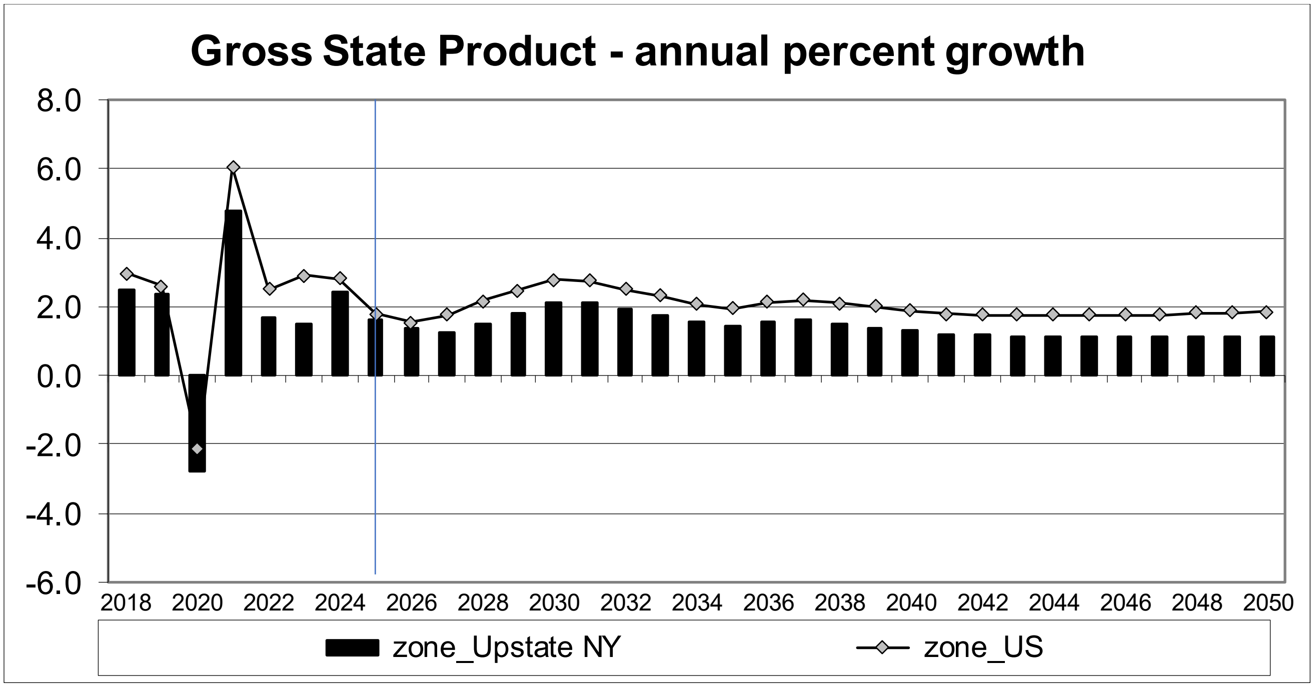

Figure 11: Annual Growth Rates of US and NY GSP

- <u>Employment per household</u> for the usage per customer forecast for the commercial sector.
  - Higher employment per household indicates that as more individuals are employed, businesses grow to accommodate the expanding workforce, leading to increased commercial demand.

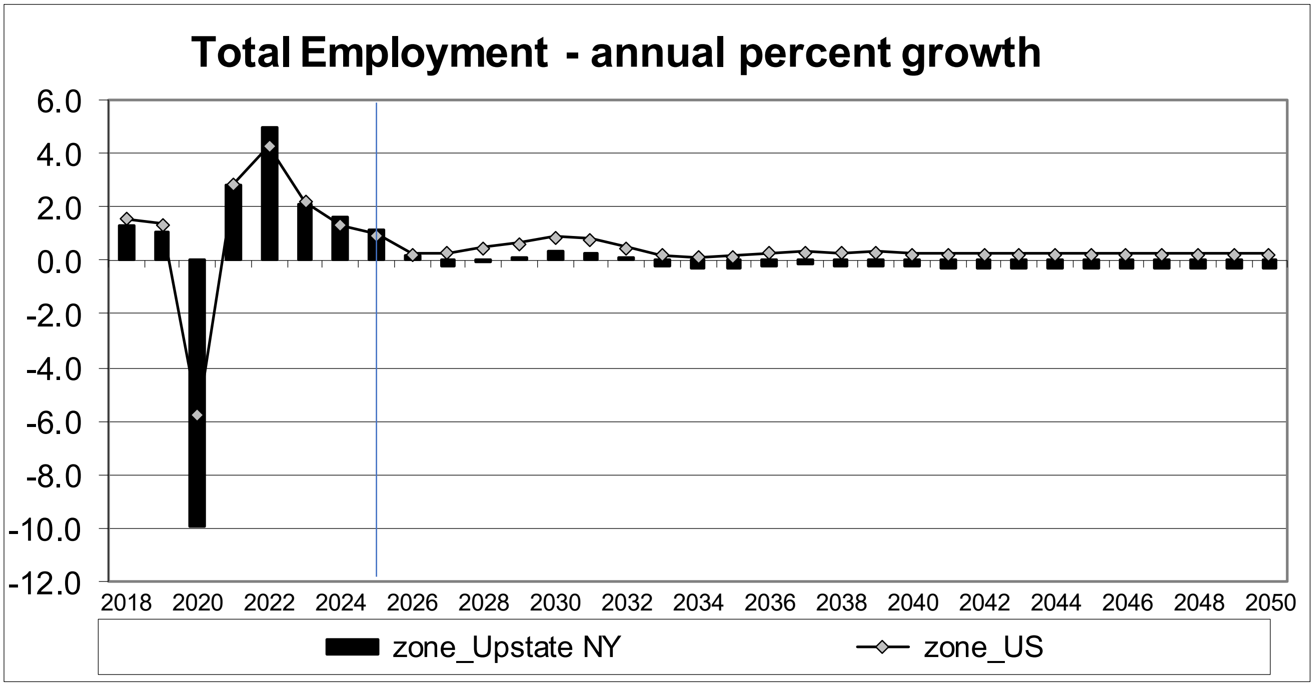

Figure 12: Annual Growth Rates of US and NY Total Employment

- <u>Manufacturing employment</u> for the customer count forecasts for the industrial sector.
    - Manufacturing employment is directly tied to production volume. Generally, as employment in manufacturing increases, it signifies higher production rates to meet demand for manufactured goods, which in turn necessitates a corresponding rise in energy demand.

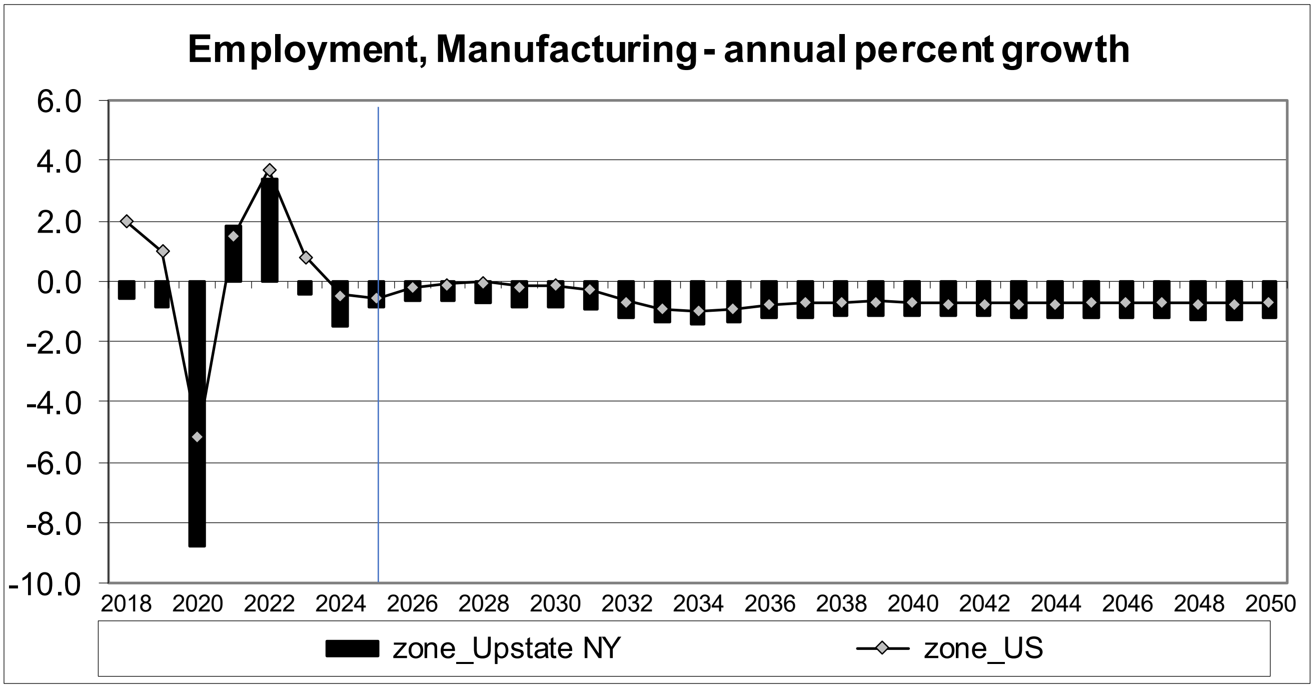

Figure 13: Annual Growth Rates of US and NY Manufacturing Employment

- <u>Industrial employment</u> for the total energy forecasts for the industrial sector.
    - Industrial employment is comprised of a handful of different employment sectors chosen to accurately reflect the Company's actual customer makeup. Industrial employment closely mirrors manufacturing employment as it's a component. Generally, as employment in the industrial sector increases, it signifies higher production rates to meet demand for goods, which in turn necessitates a corresponding rise in energy demand.

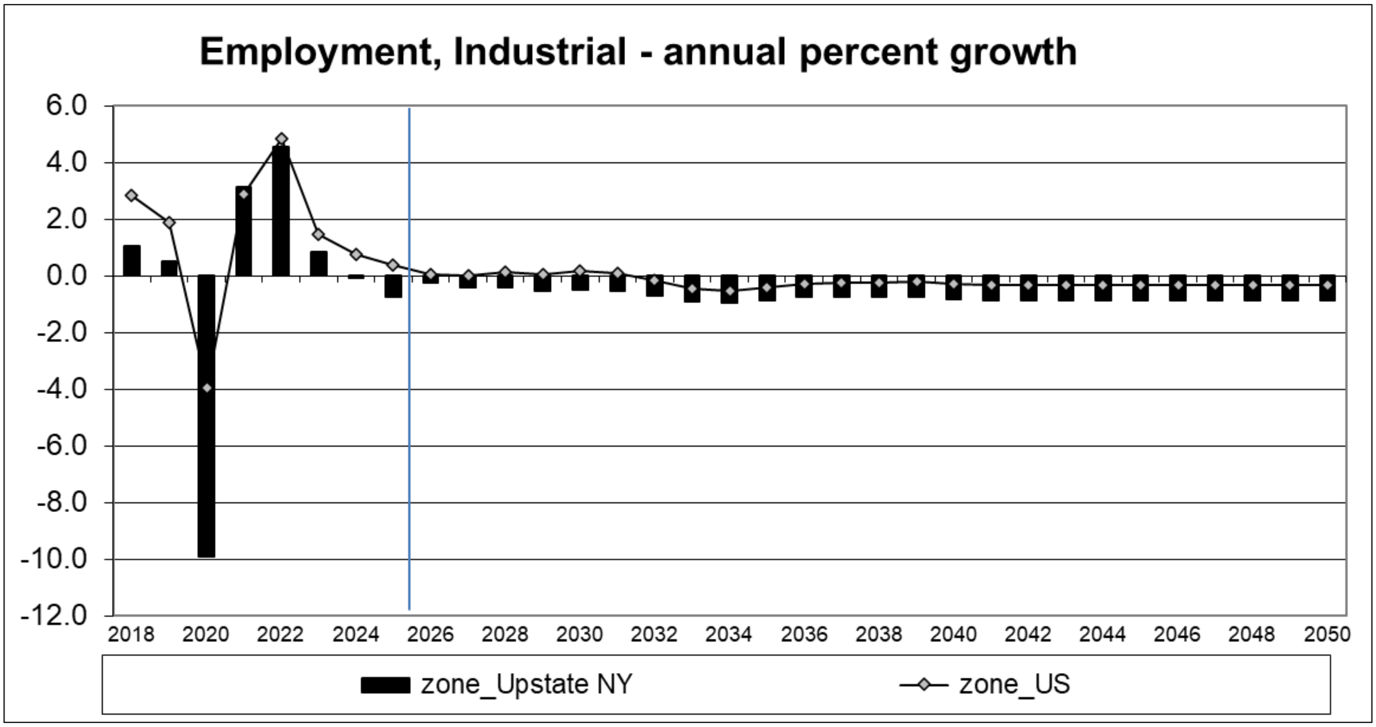

Figure 14: Annual Growth Rates of US and NY Industrial Employment

4.1.3. Feeder Level Baseload

The feeder level Baseload forecast, and demand assessment produce seasonal peak loads and hourly load profiles. The seasonal peak load is derived from applying the zonal level weather adjustment factors and Baseload growth rates to the most recent historical feeder peak load. The weather adjustment factors are derived from comparing the last known actual peak load with what the 50th, 90th, and 95th load would be under the possible Baseload peak-creating scenarios. The purpose of weather adjustment is to bring the Baseload to the desired quantile(s) which can then grow into the future. The weather-adjusted historical feeder peak load will then grow at the same rates as the zone that it falls in. Using the zonal level growth allows capturing the regional economic and demographic changes which are key drivers of the underlying Baseload growth. Such a process results in dual-point seasonal peak point forecasts between 2026 and 2050 for each feeder.

The estimated seasonal peak loads are then applied to a normalized (i.e., the highest point of a year has value 1 and other points in the same year have a fraction) hourly profile to get the hourly load profile for each feeder. The standardized hourly profile is derived from the typical load shapes from the class average load shapes[9]. Such typical load shapes are available for typical residential, commercial, and industrial customers. A single hourly load profile is derived as the weighted average of each class's profiles using the energy share of each class at the feeder. Finally, the feeder-specific Baseload hourly profile is normalized so that the maximum value gets transformed to 1 and for each year, the max-

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[9] Load Profiles | Supply Costs | National Grid (nationalgridus.com)

normalized hourly profile is multiplied by the corresponding forecasted peak in the point forecast process to match all the forecasted seasonal peaks.

4.2. Distributed Energy Resources (DERs)

In New York State there are policies, programs, and technologies that impact customer loads. These include but are not limited to energy efficiency (EE), solar photovoltaics (PV), energy storage (ES), electric vehicles (EV), electric heat pumps (EH), and demand response (DR). These collectively are termed distributed energy resources (DERs) in this report. The overall longer-term guiding targets for the DERs is New York State's Draft State Energy Plan (SEP) which provides guidance on long-term renewables and other climate-friendly programs.[10]

A base case is developed for each of the DERs and is used for the planning forecast. In the near-term, the base case reflects Company plans, projects in the queue, and historical trends. The short-to-medium-term projections are also adjusted for impacts of different federal and state policies like tariffs, tax credits, etc., as appropriate. In the long-term, the base case is tied to state targets, market outlook studies, and public policies. In addition, a high case and low case are also developed for each DER, as appropriate. The inclusion of multiple cases for each DER, as well as the different combinations of them, provides system and strategic planners with additional information to make informed decisions, and a basis for projecting uncertainty around the forecast and demand assessment. The discussion below on each DER focuses on the base case. It most closely models a trajectory towards meeting the state's Draft SEP policy targets, but some DERs show a delay in achieving these targets. Additional details on the base case as well as high and low cases are provided later in the 'DER Cases' section and in Appendix C.

4.2.1. Electric Vehicles (EV)

System-Level Adoption Forecast

Electric vehicles are expected to significantly add to peak load over time. The Company's forecast considers load impacts on the distribution system from five types of electric vehicles: light-duty electric vehicles (LDEVs), medium-duty EVs (MDEVs), heavy-duty EVs (HDEVs), battery electric transit buses, and battery electric school buses. Impacts from two electric vehicle powertrains are modeled: all-battery electric vehicles (BEVs) and plug-in hybrid electric vehicles (PHEVs).[11] The Company's projections include charging load impacts from both personal and non-personal use electric vehicles.

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[10] See https://energyplan.ny.gov/Draft-2025

[11] These powertrains are included because vehicles with these powertrains require plugging directly into the electric system (i.e., plug-in electric vehicles, or PEVs). Other types of zero-emissions vehicles that incorporate electric battery technology (e.g., Hybrid Electric Vehicles, or HEVs) are not included since they still rely on fossil fuels for their energy and do not charge from the system. Similarly, hydrogen-based fuel cell electric vehicles (FCEVs) are not included since they do not directly use electricity from the grid to meet their energy needs. Although potentially significant quantities of electricity would be required for electrolyzer facilities to perform hydrolysis on scale to generate the necessary hydrogen for FCEVs, there are significant uncertainties on where these facilities would be built (within and across states and service territories) and to what extent these impacts would be borne by the electricity distribution system. Currently, the long-term expectations are that these facilities would generate primarily transmission-side impacts, which aligns with the MA

A stock-flow modeling framework is leveraged to project the count of electric vehicles by type through the forecast horizon and the demand assessment period. The primary inputs into the model are: (1) the total stock of vehicles-in-operation (VIO) over time, including both electric and non-electric vehicles; (2) the total volume of vehicles scrapped each year by powertrain type; (3) the portion of new vehicle sales by year that are expected to be zero-emissions vehicles (ZEVs) as well as the subset of new ZEV sales that are expected to be BEVs and PHEVs, respectively.[12] Total electric vehicles are calculated for each year by adjusting the prior year's count based on the net impact of new sales and scrap that occurred in that year.

For (1), historical vehicle counts for light-duty vehicles and both school and transit buses are sourced from the registration database released by the New York Department of Motor Vehicles (DMV).[13] Vehicle counts for school buses and transit buses are further supplemented and validated using depo-specific vehicle counts. Vehicle counts for these classes are projected forward using Moody's baseline household forecasts for the service territory, as regional demographic dynamics are expected to be the biggest and primary driver of long-term vehicle stock growth trends.[14] This also ensures vehicle trends are consistent with customer count projections for the service territory, as household growth is a driving economic factor in those models.

For the remaining MHDV types, historical vehicle counts are estimated using S&P Global's proprietary vehicle-in-operation database, which leverages transaction and shipping data, Original Equipment Manufacturer (OEM) data, and other sources to build a comprehensive locational view of vehicle operations and garaging behavior. It is necessary to use this source instead of DMV data because registration data does not capture out-of-state registered vehicles operating in the territory, which is especially common for medium- and heavy-duty fleet vehicles.[15] These MHDV counts are projected forward using national vehicle stock growth rate projections available provided in the Economic Transition Scenario (ETS) published by BloombergNEF as part of their 2025 EVO.[16,17,18]

CECP assumptions for associated electrolyzer impacts. As such, they are currently excluded from system-level, distribution load modeling efforts, but will be reevaluated as real-world data becomes available.

[12] For LDVs, all ZEV sales are assumed to be either BEV or PHEV (i.e., no FCEVs). For MHDV types, all plug-in electric vehicles (PEVs) are assumed to be BEVs (i.e., no PHEVs). Furthermore, for school buses, all ZEV sales are assumed to be BEVs (i.e., no FCEVs or PHEVs). These assumptions reflect the variable use cases of FCEV and PHEV technology across different market segments and align with current policies and market forces driving customer adoption.

[13] https://dmv.ny.gov/records/statistical-data

[14] Note, there are significant uncertainties in the long-term trends of number of vehicles per household, especially with the potential advent of self-driving cars and more ride-sharing overtime. Until the impacts of these factors become more measurable, it is assumed that the number of vehicles per household remains roughly constant through the forecast and demand assessment period, in line with recent history.

[15] In contrast, light-duty vehicles, school buses, and transit buses are expected to have a higher correlation between where they operate and where they are registered.

[16] See https://about.bnef.com/electric-vehicle-outlook/

[17] Unless otherwise noted, all insights derived from BloombergNEF's 2025 EVO report are based on the Economic Transition Scenario (ETS) which represents their most likely, baseline scenario. A net-zero scenario that reflects more aggressive rates of electrification are also included in the report, although these projections exceed the general pace that transportation electrification is expected to take based on current regulations, historical trends, and market forces.

[18] National estimates are expected to more closely align with longer-term stock trends for certain MHDV types because economic and demographic factors outside the service territory play a bigger role in driving stock changes for these

For (2), the stock-flow model's scrap module has been enhanced this year to better reflect average service life expectations for each vehicle type as well as the current age mix of vehicles in operation. This was achieved by developing scrap rate distributions by vehicle age for each type of vehicle using insights gleaned from National Highway Traffic Safety Administration (NHSTA) research on vehicle survivability curves[19] as well as data on vehicle service life from BloombergNEF's annual Electric Vehicle Outlook (EVO) report. Along with the change in total vehicle stock (1), the volume of vehicles scrapped across all types (2) can be used to calculate the implicit volume of new vehicle sales necessary to realize the overall change in vehicle stock in a given year.

For (3), the total volume of new sales is combined with ZEV sales share assumptions to generate total volumes of new ZEV sales by year and vehicle type. In prior years, these ZEV sales shares assumptions were informed by enforceable rules and regulations on the books.[20] However, due to federal action taken in 2025 against the EPA waivers that allow California to set more stringent EV adoption standards (and in turn for NY to adopt them), there is significant uncertainty around whether these rules will be upheld and/or the waiver repeal will be overturned. As this will likely be decided only after a protracted period of litigation, the ZEV assumptions have been updated for this forecast to align with the recently released SEP assumptions by vehicle type.[21] The SEP scenarios, which are informed by the ACC-II and ACT rules, provide ZEV sales pathways through 2050 that are tied more generally to state decarbonization goals, leaving room for alternative policies (to the ACC-II and ACT) to be developed to achieve said goals.[22] Enforcement of the ACC-II and ACT has already been waived for model years 2026 and 2027.[23] Thus, historical ZEV sales trends are projected forward to estimate new ZEV sales during this period. For school buses, which are subject to their own electrification mandate, ZEV sales are set to align with the policy, assuming some school districts will request and receive an extension waiver to delay compliance, as allowed in the latest state budget.[24] The estimated impacts on EV adoption from higher vehicle prices due to federal tariffs and the repeal of federal tax incentives are used to adjust ZEV sales downward in the near- to medium-term for all vehicle types.[25] In terms of

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segments, especially given the large presence of out-of-state registered vehicles simply passing through the service territory and/or doing business in surrounding states.

[19] See https://crashstats.nhtsa.dot.gov/Api/Public/ViewPublication/809952

[20] Namely, for light-duty vehicles (LDVs), New York had adopted California's Advanced Clean Car II (ACC-II). For MHDVs, New York had adopted California's Advanced Clean Trucks (ACT) rules. See http://dec.ny.gov/news/press-releases/2022/12/dec-announces-adoption-of-advanced-clean-cars-ii-rule-for-new-passenger-cars-and-light-duty-truck-sales & https://ww2.arb.ca.gov/our-work/programs/advanced-clean-trucks.

[21] In particular, the assumptions from the Additional Action Policy from the draft SEP released in the summer of 2025 are used to drive ZEV sales shares in the base case for all vehicle types except school buses due to the presence of the school bus electrification mandate, which imposes specific electrification requirements on that segment. For more details on the draft SEP, see https://energyplan.ny.gov/Draft-2025.

[22] That said, however, the ZEV sales shares in the NY SEP by vehicle type are nevertheless largely aligned in the long-run with the corresponding ZEV sales by vehicle types under the ACC-II and ACT rules and regulations. In the short-run, NY SEP ZEV sales shares lag the ACC-II and ACT rules, reflecting slower historical adoption and market headwinds.

[23] https://dec.ny.gov/news/press-releases/2025/5/nys-department-of-environmental-conservation-acts-to-sustain-support-for-statewide-transition-to-cleaner-vehicles

[24] For the electrification mandate, see https://www.nyserda.ny.gov/All-Programs/Electric-School-Buses. For information on the process for school districts to request an extension waiver, see https://www.nysed.gov/sites/default/files/zeb-extension-waiver-guidance-final.pdf.

[25] Current tariff structures, which only impact imported vehicle sales, are estimated to raise new vehicle prices by ~10% on average. The repeal of federal tax credits will have a similar impact on effective new electric vehicle price, subject to credit utilization assumptions. Combined with consumer elasticity assumptions, this corresponds to around a 20% decline in EV sales relative to what they would have been through the end of the decade.

the ZEV sales share mix across powertrains, insights gleaned from BloombergNEF's EVO outlook are used to break out sales across powertrains through the forecast horizon and demand assessment period. Figures 15 and 16 show the historical and estimated number of EVs in National Grid's New York jurisdiction. By the end of 2025, it is estimated that about 52,600 EVs, across all vehicle types, will be on the road, growing to about 757,700 by the end of the forecast horizon and further to about 2,086,400 by the end of the demand assessment period.

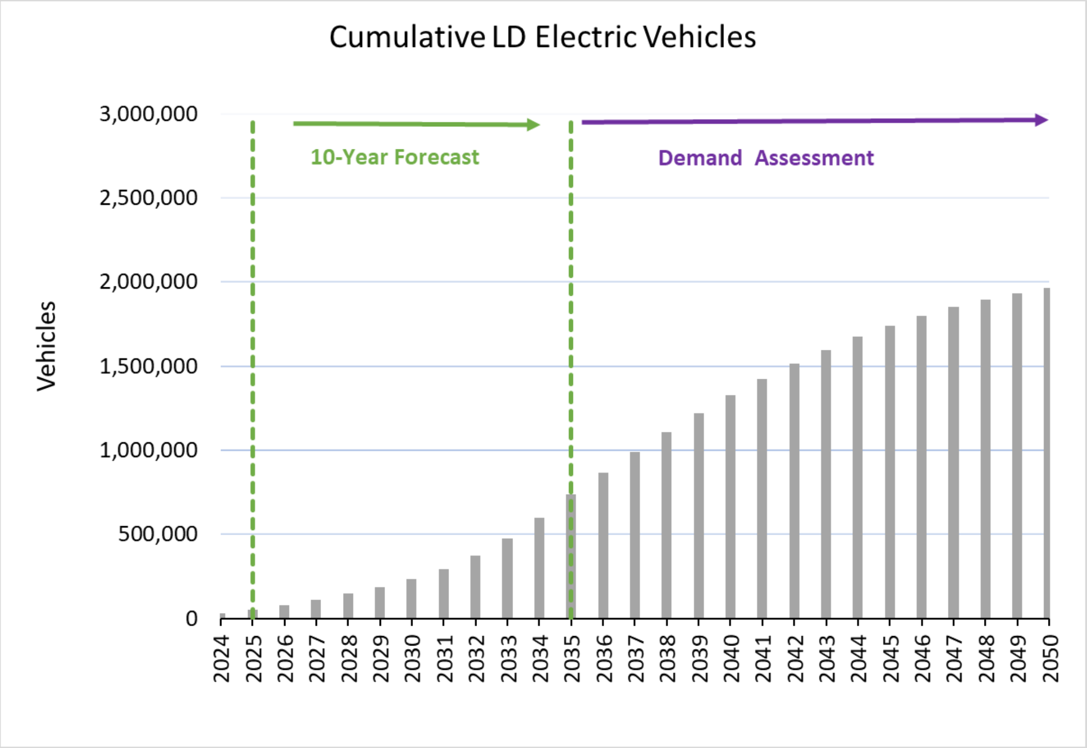

Figure 15: Cumulative LD EVs in National Grid's New York Service Territory

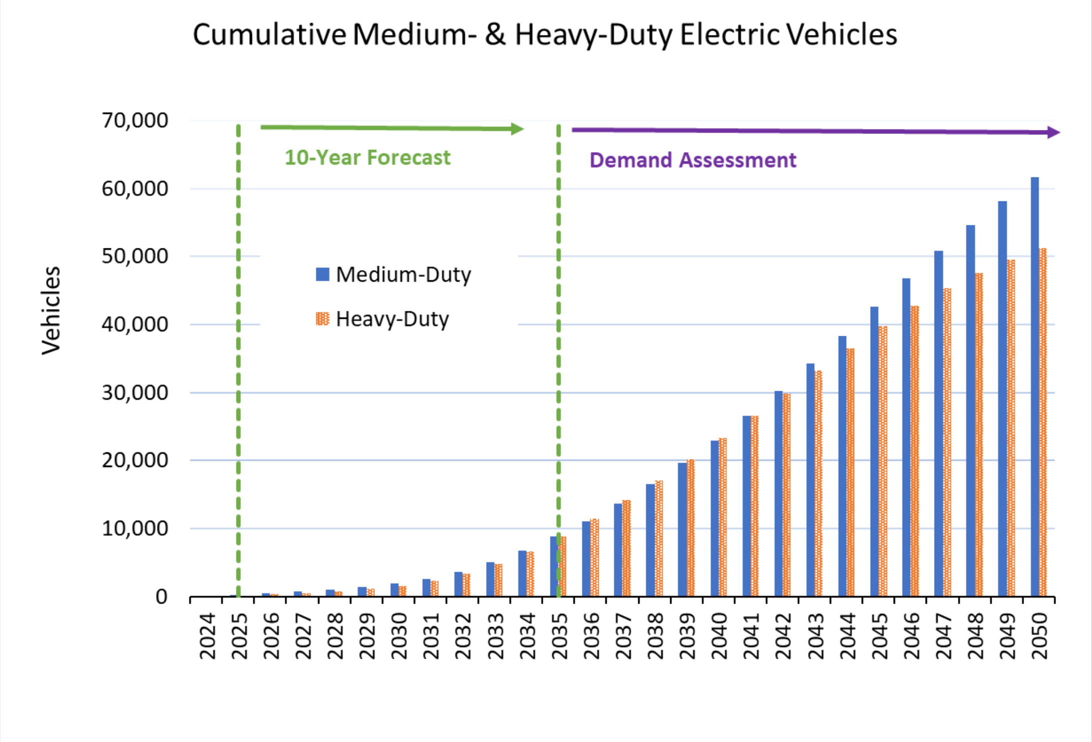

Figure 16: Cumulative MHD EVs in National Grid's New York Service Territory

<u>Feeder-Level Adoption Forecast</u>

Light Duty

The allocation of light-duty electric vehicles (LDEVs) is conducted through a structured and empirical methodology that translates the Company's system-level adoption forecast into feeder-level projections. The system-level forecast reflects projected LDEV adoption across the Company's service territory, as described in the System-Level Forecast subsection. Consistent with observed market trends, the majority of projected LDEV adoption is attributed to personal use and allocated to residential customers. The remaining portion of adoption corresponds to commercial use and is allocated to commercial and industrial (C&I) customers connected by each feeder.

Personal LDEV adoption is allocated using a generalized propensity-based modeling approach that captures the relationship between localized socio-economic characteristics and electric vehicle adoption rates. The socio-economic information from American Community Survey (ACS) - U.S. Census Bureau[26] is used for building the propensity model. In the current implementation, the principal explanatory variable is higher educational attainment, defined as the percentage of the population aged 25 and older holding a bachelor's degree or higher. This variable has been identified as a robust indicator of early electric vehicle adoption and is used to differentiate relative adoption potential across geographic areas. Propensity scores are calculated at the census-tract level and subsequently translated to the feeder level using geospatial mapping techniques. For feeders intersecting multiple census tracts, a weighted average propensity score is calculated, with weights based on the number of residential

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[26] https://www.census.gov/data/developers/data-sets/acs-5year.html

customers served in each tract. Overall, areas with higher levels of educational attainment and longer average commute times are projected to experience relatively faster personal LDEV adoption, particularly in the early and mid-forecast years. Non-personal LDEV adoption is allocated using a proportional allocation methodology. Annual incremental non-personal LDEV adoption is distributed across feeders based on each feeder's share of total commercial and industrial customers within the Company's service territory. This approach reflects the current absence of granular, location-specific forecasting data for commercial fleet electrification while ensuring that adoption levels remain aligned with observed customer distributions.

Following the initial allocation, an optimization process is applied to ensure that feeder-level projections satisfy key planning and operational constraints. Specifically, the optimization ensures that:

1. Feeders with higher relative propensity scores experience correspondingly higher adoption growth, particularly in the early forecast period.
2. Projected LDEV counts on each feeder do not exceed reasonable maximum vehicle ownership levels, as estimated based on the number and type of customers connected.
3. The aggregate feeder-level adoption projections reconcile exactly to the Company-level LDEV projections at each year of the planning horizon.

To reflect expected market maturation and saturation effects, the influence of the propensity model is assumed to decay linearly over time. As a result, differences in new adoption growth will gradually shrink and are set to be consistent across all feeders by the end of 2040, leading to a more uniform distribution of incremental LDEV adoption by the end of the assessment horizon.

Medium- and Heavy-Duty

Separate allocation frameworks are employed for depot-based versus public on-route charging as not all charging is expected to be met by a single location/source for any type of MHDV. For depot-based charging impacts, a two-step allocation framework is leveraged to allocate MHD vehicles (EV & non-EV); (1) allocate vehicles from the system-level to the feeder level using relevant economic indicators, such as VIO shares by ZIP code from Polk and feeder-level commercial and industrial energy shares across ZIP codes; (2) override the allocation using high-resolution fleet depot information from the Company's fleet depot database of identified fleets.[27] This ensures the allocation incorporates information on known fleets while being consistent with more aggregate economic and demographic data. Final adjustments are made to feeders with less fleet presence to ensure the aggregation of MHDVs across feeders aligns with the system-level MHDV count. Feeder-specific MHDV counts are assumed to grow and electrify in line with the system-average pace for each MHDV type.[28] In this way, all feeders match the system-level trends, although there is variability across feeders based on their mix of MHDV subtypes. The MHDEV allocations by feeder are combined with depot charging load profiles to generate overall depot-related charging impacts by vehicle type.

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[27] The fleet depot database has been updated this year to include the Company's fleet locations as well as the latest fleet assessments in the service territory as part of the Company's Fleet Assessment Services Program (FASP).

[28] Given limited electrification to date for the MHDV segment, it is currently not possible to build statistical regression-type models for relative adoption propensity across fleets and geographies. Although this limitation will likely remain for years to come, it will be an area of further investigation in future cycles, once there is a sufficient pool of adoption data .

For public, on-route charging, a more generic procedure is implemented to allocate load impacts across identified public sites throughout the service territory.[29] In particular, a composite indicator consisting of (1) relative share of VMT (as a proxy for vehicle traffic, demand, and stops)[30] and (2) relative share of available parking spaces (as a proxy for site-level space constraints) is developed.

The specific VMT measure used (e.g., for combination versus single-unit trucks) as well as the space constraint factor varies by MHDV type. Additionally, the types of public sites where charging is expected to occur vary by MHDV type. For instance, heavy-duty long-haul tractor trucks are expected to rely mostly on opportunistic on-route highway charging to meet charging needs because off-highway charging would take them too far off route. In contrast, other MHDV types are assumed to rely primarily on off-highway charging as on-highway charging is likely off their more regional routes. On-highway charging is also expected to be relatively more expensive, discouraging use unless necessary, likely for more schedule and operationally constrained long-haul heavy-duty truckers. Ultimately, system-level public charging load impacts are shared down to relevant public sites and their associated feeders using the composite indicator, at which point the public charging impacts are combined with depot impacts to generate total feeder-level charging load impacts.

Profiles

Electric vehicle charging load profiles are estimated for light-duty, medium-duty, heavy-duty, transit buses, and school buses. Profiles are generated on a per vehicle basis in a four-step process that entails: (1) projecting annual vehicles miles traveled (VMT) by vehicle type; (2) allocating annual VMT across each day of the year, adjusting for monthly- and day-type effects; (3) combining daily VMT with daily temperature and battery efficiency assumptions to estimate daily energy demands; (4) applying normalized charging load shapes to daily energy amounts to generate charging load profiles.

Historical annual VMT is sourced from NYISO for regional use vehicle types, which includes light-duty vehicles, school buses, and transit buses. For medium- and heavy-duty vehicles, historical VMT is sourced from the U.S. EIA's 2025 Annual Energy Outlook (AEO).[31,32] VMT is projected forward

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[29] Public sites include on-highway charging plazas, rest areas and stops along highways, and off-highway gas stations, and other similar locations where MDHV charging is expected to occur. While a subset of existing charging infrastructure is currently located in shopping plazas, space and capacity constraints suggest these stations will continue to primarily serve LDEV charging needs. As such, shopping plazas have been excluded from the public charging site list. In many cases, the locations of gas stations are highly correlated with the location of shopping plazas anyway as there are incentives for businesses to locate near each other.

[30] VMT data is sourced from the FHWA's Highway Performance Monitoring System (HPMS) database which distinguishes between overall VMT across all vehicle types and tractor truck-specific VMT. Source located here: https://www.fhwa.dot.gov/policyinformation/hpms.cfm

[31] The EIA estimates for these classes better align with other sources mentioned, including VIUS and ISO-NE. For additional information on EIA's forecasts, see https://www.eia.gov/outlooks/aeo/tables_ref.php.

[32] For the same reason national-level forecasts are used to drive MHD stock trends, it is necessary to tie historical MHD VMT values to national values, as VMT from in-state registered vehicles is likely to underestimate actual average annual VMT since in-state registered vehicles tend to operate in smaller areas.

using EIA's AEO reference case projections for the light-duty class[33] and BloombergNEF's EVO ETS projections for the other classes.[34] In general, it is assumed that annual driving miles are comparable across all powertrains (i.e., traditional combustion engine vehicles are driven as much as battery electric vehicles). For the PHEV light-duty profile, however, annual VMT is adjusted to account for the portion of annual miles that are expected to be driven in electric mode (as opposed to using traditional carbon fuels). This share is estimated based on BloombergNEF's EVO and is expected to increase overtime as PHEV technology continues to improve. Meanwhile, for MHDVs, to generate the on-depot versus off-depot profiles, a portion of annual VMT (i.e., energy) is split between these locations based on SME input, which allows different charging behavior (i.e., load shapes) to be reflected in each profile. Monthly- and day-type effects are sourced and estimated from ISO-NE and NYISO, which ultimately base their estimates on state RMV and DMV data, respectively. Battery efficiency assumptions are also derived from ISO-NE and align with empirical deployment data. At the same time, temperature data aligns with the weather data used elsewhere in the peak modeling process.

The relative charging load profile for LDEVs are derived from ISO-NE's 2019 ChargePoint study[35] and reflect unmanaged charging behavior.[36] Since the charging load shape reflects charging behavior across all locations (i.e., home, work, and public), the aggregate profile is adjusted to generate location-specific curves using locational energy shares derived from NREL's EVI Pro-Lite tool.[37] For medium- and heavy-duty vehicles proper, on-depot profiles are based on fleet cluster analyses conducted by Hitachi Energy using deployment data from CALSTART.[38] For transit buses, on-depot profiles are based on the load analysis conducted by ElectroTempo as part of their depot identification study.[39] School bus on-depot profiles have been updated this year to align with NYISO's load shapes, which show more reasonable timing for intra-day charging. Finally, public charging load profiles for MHD vehicles are estimated using the load curves from the 2022 Electric Highways study, with different profiles for heavy-duty and non-heavy-duty vehicle types.[40]

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[33] The EVO light-duty VMT projections display quite aggressive growth, which is partially offset by more conservative stock growth assumptions (leading to more plausible aggregate VMT trends). This is primarily driven by assumptions related to more autonomous cars on the road, leading to reduced vehicle ownership while increasing miles traveled for each vehicle, on average, thanks to increased ridesharing and carpooling. Since the EVO stock growth assumptions are not used for LDVs, it thus becomes necessary to not use the VMT growth assumptions either.

[34] While the EVO MHD historical VMT estimates are not used, the VMT growth trends are adopted as they are generally considered more plausible than the EIA's forecasts, which show significant declines in VMT year-over-year, a trend that is largely ahistorical. In contrast, the EVO generally shows flat VMT growth, which is more aligned with recent history.

[35] See ISO-NE Analysis of 2019 ChargePoint data

[36] Note, the base case light-duty charging profile does not include any managed charging impacts, but smart charging assumptions are incorporated into the low case light-duty charging profile (details in Appendix E).

[37] See https://developer.nrel.gov/docs/transportation/evi-pro-lite-v1/ for the tool itself. See the NREL API for additional documentation on their methodology which relies on a simulation-based approach.

[38] https://calstart.org/projects/medium-heavy-duty-ev-deployment-data/

[39] ElectroTempo used machine learning models to build probabilistic land parcel-level identify depot sites and fleet sizes across the Company's NY and MA service territories. For each depot, charging load profiles were generated for each fleet using arrival and departure data to estimate daily average energy needs, which was combined with dwelling/stop time data and other charging assumptions to produce hourly load profiles that could be aggregated by vehicle class.

[40] In particular, the constrained, 2045 MHDV sales scenario is used, which is the more delayed of the two scenarios considered in the study and most closely aligns with the assumptions underlying the base case for MHDV adoption.

4.2.2. Electric Heat Pumps (EH)

System-Level Adoption Forecast

The state of New York's commitment to reducing its greenhouse gas emissions relies heavily on cutting emissions from its residential and commercial buildings. One core strategy for decarbonizing those buildings is the electrification of space heating with efficient electric heat pumps. The focus of this section is on the electrification of residential and commercial space-heating systems, as well as the changes in people's cooling behavior resulting from heat pump adoption. The electrification of other building end-uses like water-heating, cooking, and drying are outside the scope of the forecasts released with this report.

The electrification projections are first developed based on projected residential and commercial heat pump adoption derived from program savings targets established in the New Efficiency: New York (NE: NY) Order for 2025 (Order Authorizing Utility Energy Efficiency and Building Electrification Portfolios through 2025, dated January 16, 2020, Case 18-M-004). From 2026 through 2030, projections reflect the Company's plans outlined in the Energy Efficiency and Building Electrification (EE/BE) Order (CASE 18-M-0084 and Case 14-M-0094).

Post 2030, heat pump penetration rates transition toward alignment with the pathway identified in New York's Draft SEP Additional Action (SEP – AA) scenario.[41] All of these projections are then adjusted to reflect the estimated impacts of federal tariff-related price increases, which are expected to dampen heat pump demand in the near to medium term and result in modestly lower penetration rates during that period.[42] These impacts are offset by increased adoption driven by all-electric building (AEB Act) requirements, which are expected to accelerate heat pump installations in the new construction and major renovations market.[43][44][45] Under the base case, the penetration at the end of forecast horizon in 2035 is 16% for residential sector and 6% for commercial sector. The corresponding penetration for

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[41] See https://energyplan.ny.gov/-/media/Project/EnergyPlan/files/2025-Energy-Plan/Summary-for-Policymakers.pdf for final version of new State Energy Plan. The forecast used the draft version released in September 2025.

[42] Based on research across multiple sources and news articles, we modeled several tariff-driven price-increase scenarios, ranging from high and persistent tariffs to low and temporary ones, resulting in estimated price impacts of 10%–40%. These scenarios were combined with a range of HP price-elasticity assumptions to quantify the potential impact on demand. The 50th percentile of the resulting distribution was used as the Base Case estimate, indicating an average demand decline of approximately 10%, which gradually tapers off and fully normalizes by 2030.

[43] See https://www.nysenate.gov/legislation/bills/2023/S562/amendment/A

[44] The AEB Act restricts the use of fossil fuels in new building construction and major renovations. Its impact on new construction is determined from projected residential customer growth which is adjusted down to reflect exemptions and hard-to-electrify situations. The impact from rebuilds are estimated based on historical relationships between rebuild activity, annual completions, and overall building stock. Historical data from Moody's show that rebuilds represent a small fraction of total housing completions and, an even smaller fraction of overall housing stock. This share of rebuilds in total stock is applied to current meter counts, to obtain an estimate of rebuilds per year, which are then reduced to account for exemptions and hard-to-electrify situations based on SME guidance.

The combined effect of these adjustments estimates AEB-driven heat pump installations to account for about 10% of total installations over 2026-2033. The AEB adjustments also lead to a higher share of full heat pumps in total installations.

[45] Explicit AEB adjustments are applied only through 2033 because the SEP AA scenario inherently incorporates AEB impacts when projecting heat-pump penetration. In the near term, however, adoption figures are based on internal company plans and subsequent smoothing, so a separate AEB adjustment is required. Over the longer term, AEB effects are assumed to be fully captured within the SEP scenario.

the two sectors increases to 44% and 18% at the end of load assessment horizon in 2050. Figure 17 shows the heat-pump adoption by customer class.

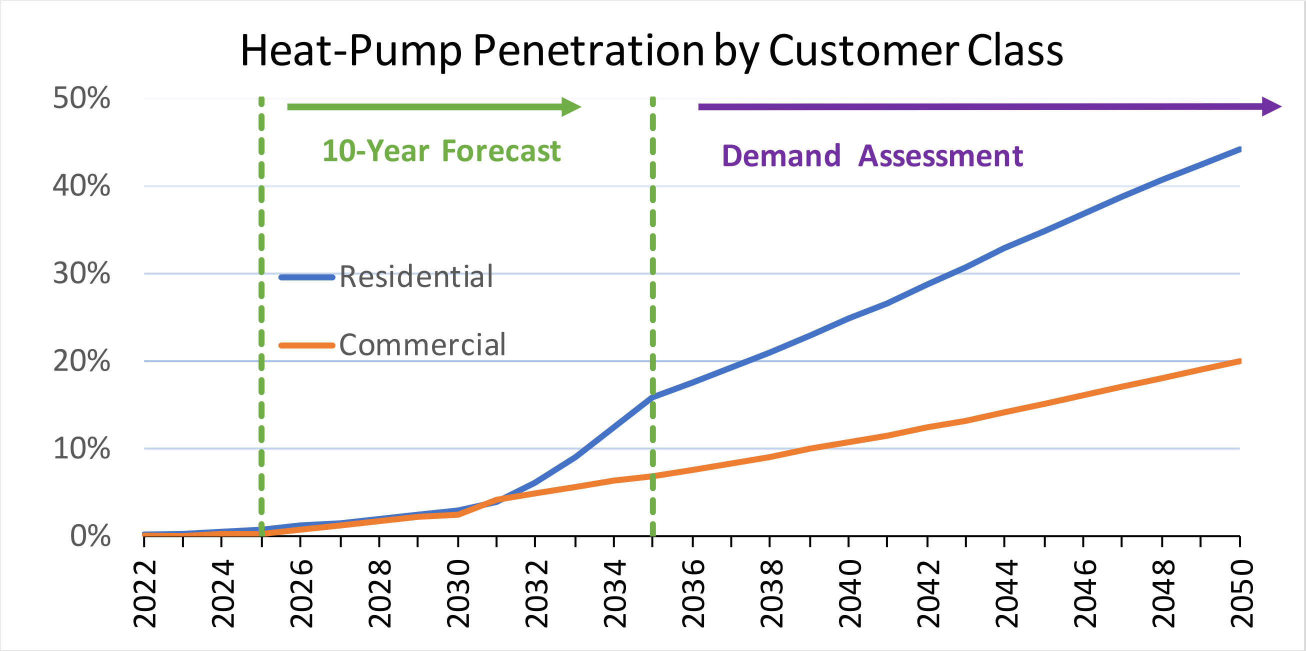

Figure 17: Heat Pump Penetration by Customer Class

The forecast models two types of heat-pumps – full and partial. Full heat pumps (FHP) are sized to meet the customer's full space heating requirements and are assumed to have no back-up heating fuel (that is, delivered fuels or natural gas). FHPs are further distinguished into ground-source (GSHP) and air-source (ASHP) heat pumps. GSHPs are assumed to be more efficient than ASHPs and perform better in colder temperatures. The efficiency and performance of cold-climate ASHPs, which is measured by the coefficient of performance (COP), continually decreases with falling temperatures, and becomes 1 (same as Electric Resistance) when it gets colder than negative 19 degrees Fahrenheit. Partial heat pumps (PHP) are assumed to switch to their supplemental fuel when outside temperatures are 30 degrees Fahrenheit or lower. The residential sector is projected to have approximately 50% of all installations as FHP by 2035, increasing to about 90% by 2050. In the commercial sector, about 90% of installations are expected to be FHP by 2035, and remain stable through 2050 (see Figures 18 and 19).

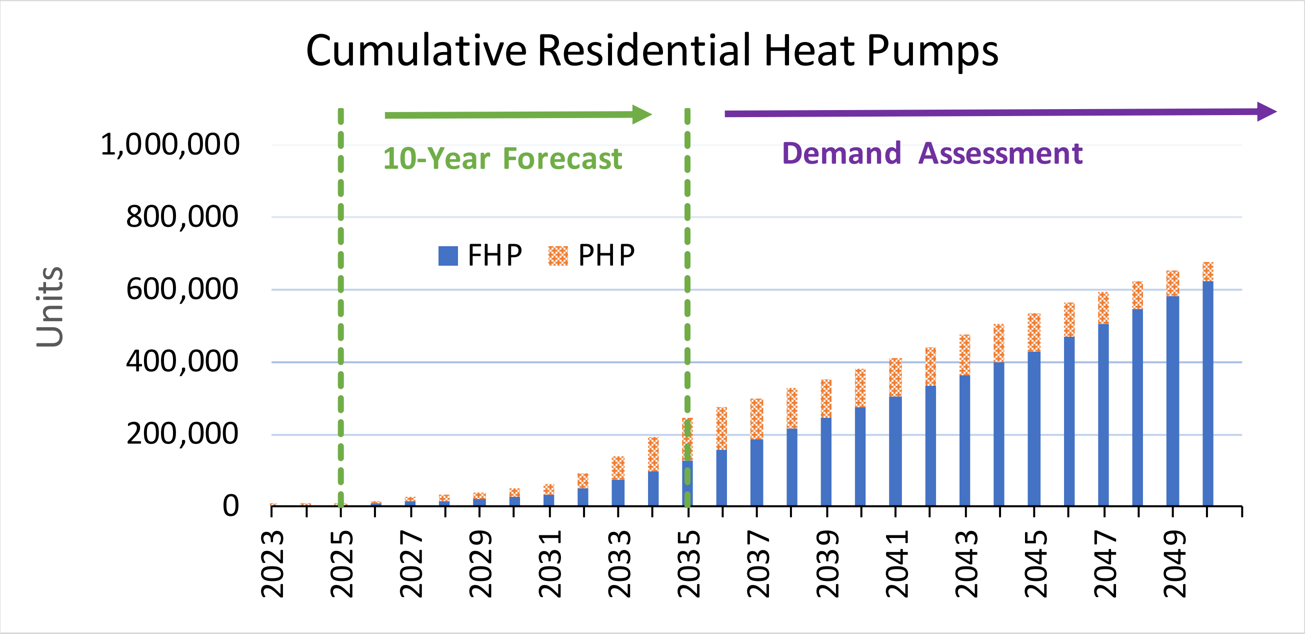

Figure 18: Residential Heat Pump Adoption

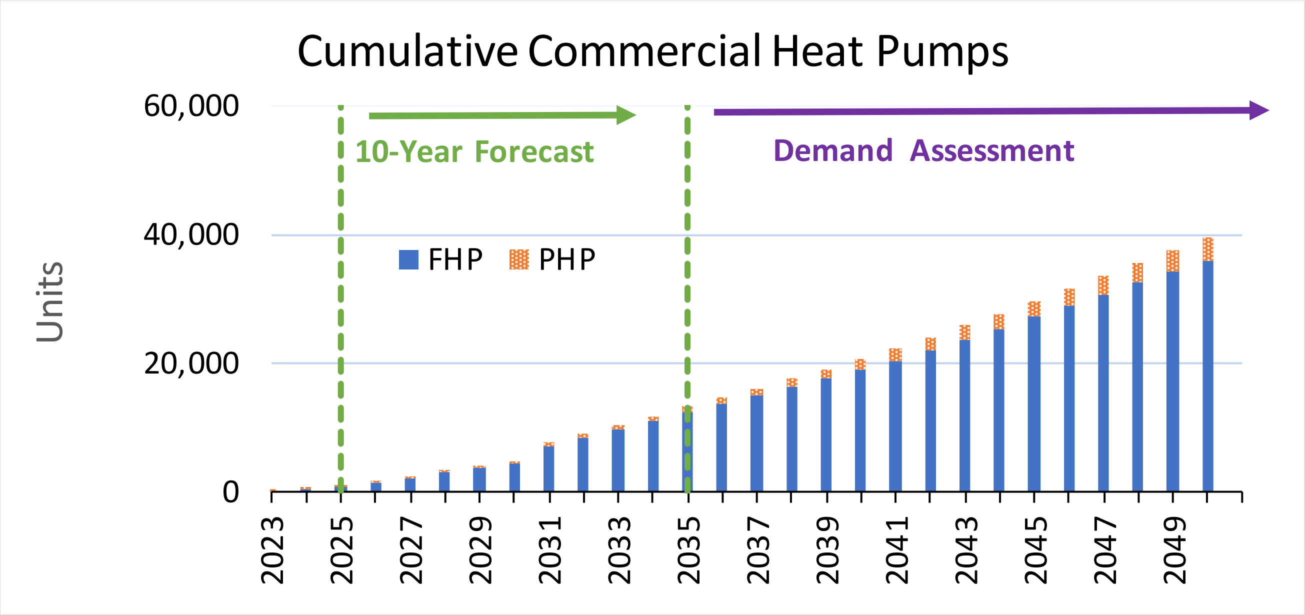

Figure 19: Commercial Heat Pump Adoption

Feeder-Level Adoption Forecast

The Company allocates projected electric heat pump adoptions to the feeder level using a data-driven methodology designed to ensure consistency with State electrification policy, system-level forecasts, and observed customer behavior. This methodology integrates multiple data sources, including the State's preferred electrification pathways, the Company's system-level heat pump adoption projections, historical Company heat pump installation records, and localized socio-economic and household heating fuel data obtained from the U.S. Census Bureau's American Community Survey (ACS).

For the near term (through 2030), feeder-level heat pump adoption is allocated based on historical installation trends. During this period, the Company assumes that the geographic distribution of heat pump incentive program participation remains consistent with historical experience. Beyond the near-term forecast period and through 2050, the Company applies a propensity-based modeling framework to reflect spatial variation in heating electrification adoption across feeders. The objective of this modeling approach is to identify relative differences in adoption potential associated with local housing and socio-economic characteristics, while ensuring that aggregate adoption remains consistent with State policy targets and system-level forecasts. The propensity model incorporates key explanatory variables that have been shown to correlate with residential heating electrification decisions, including housing tenure (owner-occupied versus renter-occupied units), educational attainment (measured as the percentage of the population with a bachelor's degree or higher), and housing stock age, represented by the median year built. These variables are derived from the ACS 2023 dataset and are applied consistently across the Company's service territory.

Propensity scores are initially calculated at the census-tract level and then mapped to the feeder level using geospatial overlay techniques. For feeders intersecting multiple census tracts, a weighted average propensity score is calculated, with weights based on the number of residential customers served in each tract. This methodology preserves the spatial resolution of the underlying demographic data while ensuring proportional representation at the feeder level. Consistent with the model results, feeders serving areas characterized by higher owner-occupancy rates, higher levels of educational attainment, and newer housing stock are projected to experience relatively higher rates of heat pump adoption during the near- and mid-term forecast period. To reflect expected market maturation and increasing adoption across broader customer segments, the influence of the propensity model is assumed to decay linearly over time. As a result, differences in feeder-level adoption rates progressively diminish, leading to a more uniform distribution of incremental heat pump adoption across the system near the end of the assessment horizon. This allocation framework ensures that long-term feeder-level projections remain directly aligned with State policy objectives while accounting for increased uncertainties when localized socio-economic differentiation becomes less material for future adoptions.

Profiles

The heat-pump load profiles are developed by studying the simulated heating and cooling behaviors of a sample of residential and commercial buildings in the state of New York, and adjusting those to account for Company's peak weather assumptions, conventional growth in space heating and cooling requirements, changes to customers' cooling behavior subsequent to heat pump adoption, improvements to building envelopes, and heat-pump performance assumptions. The ResStock and ComStock tools by National Renewable Energy Laboratory (NREL) provided fundamental inputs for the analysis of residential and commercial space-heating and cooling requirements and development of heat-pump profiles[46][47].

The heat-pump profiles are estimated for heating and cooling demands separately, and for both the residential and commercial sectors to capture the heterogeneity in their consumption behavior. The profiles rely on the assumption that simulated heating behavior from the sampled buildings is a reasonable proxy for modeling future heat pump usage for heating. The profiles assume that cold climate heat pumps are widely available, correctly sized, and capable of meeting year-round heating and cooling needs, and that increased building efficiency measures will lower heating and cooling demand over time.

To estimate heating profile from heat pump adoption, the Company uses NREL's space-heating end-use load profiles (EULP) for New York and pairs them with NREL's building-characteristics data for its New York service territory. Using these datasets, the Company constructs an average hourly curve representing space-heating energy needs. These curves are developed under the Company's 90/10 peak-weather assumptions for both the NIMO system and each of the six zones. Heat-pump heating profiles are then created by dividing the heating-needs curves by the coefficient of performance (COP) associated with each heat-pump type.[48] The COP curve assumed for a full ASHP heat-pump was obtained directly from Massachusetts Department of Energy Resources (MA DOER). Since similar data was not available from SEP or other external studies pertaining to New York, the COP curve from Massachusetts was also adopted in NIMO. The COP curve for PHP is the same as a full ASHP for temperatures above 30°F. For temperature at or below 30°F, it is assumed that the PHP will switch to its back-up fuel which could be either electric, in which case its COP will equal 1, or other fuels like oil, gas, etc., in which case the COP can be assumed to be 0. GSHP's COP is assumed to be 4 at all temperatures. The figure below shows the COP curve for the three types of heat pumps considered in this report.[49]

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[46] The inputs used from NREL included (i) detailed building stock characteristics for the Company's New York service territory, (ii) 15 minute end use load profiles (EULP) aggregated by building type in New York, and (iii) efficiency upgrade simulations used to estimate long term heating load reductions.

[47] Resstock 2024 release 2 and Comstock 2024 release 1 are used in the modeling process.

[48] The COP is a unit-free measure of heat-pump performance and is described as the ratio of heat generated by the system to the amount of energy supplied to the system. A typical electric resistance heater should have a COP of 1 since all the energy supplied to the system is converted to heat energy. Because heat pumps move energy through mechanical advantage rather than directly from electricity, they can achieve a COP greater than 1.

[50] The SEER is commonly used in measuring cooling efficiency, which is ratio of cooling output (in British thermal units) to energy input (in watt-hours) over a cooling season. A higher SEER number indicates a more energy-efficient air conditioner or heat pump. Note the SEER2 is updated version of rating system for new units manufactured in year 2023 and after, here we used SEER instead of SEER2 as insufficient data for the updated version.

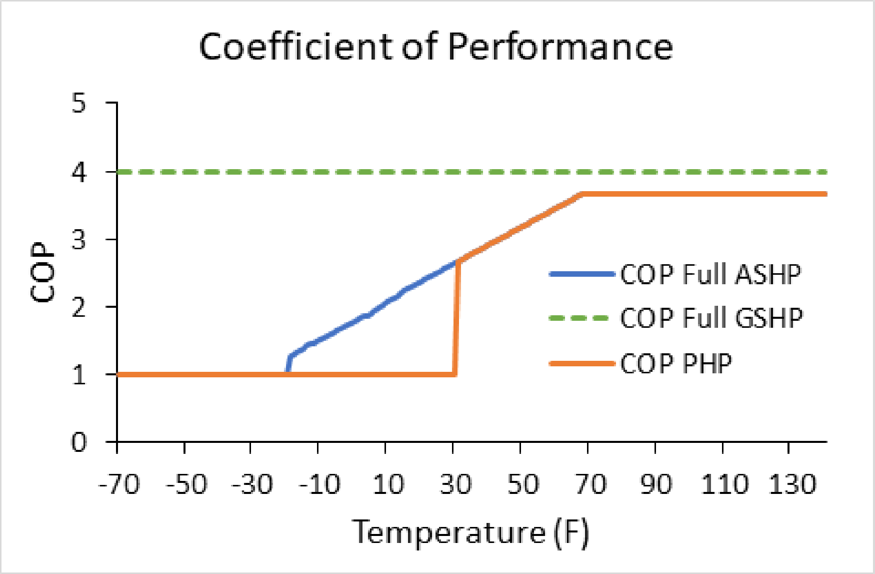

Figure 20: COP Curve by types of Heat Pump; *Source: MA DOER*

To estimate cooling demand from heat pump adoption, the Company uses NREL's simulated EULP for cooling and adjusts it for Company's peak weather assumptions and by the applicable Seasonal Energy Efficiency Ratio (SEER) for each type of heat pump.[50] The company compares average cooling behavior between customers with full air-conditioning (AC) coverage and those with partial or limited AC, and assumes that cooling demand after HP adoption will lie between the current average coverage and full coverage. The Company develops separate cooling profiles for buildings with and without existing cooling systems. Customers with AC have reduced cooling load benefited from higher heat pump cooling efficiency but increased usage due to expanded cooling coverage; their profile reflects this net impact. Customers without AC experience increased cooling load as they begin using heat pumps for cooling. The total cooling impact is a weighted average of these two profiles, based on the share of customers with and without existing AC.

The heating and cooling profiles developed above are further adjusted to reflect organic growth in heating and cooling requirements over time and account for energy efficiency improvement. The heating growth estimates are based on the forecasted growth in gas usage in the Company's gas service territory in NY while cooling growth is estimated from forecasted growth in electricity usage in Company's electric territory. The average gas usage in the residential sector is expected to remain stable over time and hence, residential profiles assume no growth in heating needs. In contrast, commercial sector profiles assume an annual growth of about 0.5%. The cooling demand is assumed to grow at 0.3% annually for both residential and commercial sectors. The energy efficiency adjustments are estimated by comparing the difference in electricity usage between the baseline

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[50] The SEER is commonly used in measuring cooling efficiency, which is ratio of cooling output (in British thermal units) to energy input (in watt-hours) over a cooling season. A higher SEER number indicates a more energy-efficient air conditioner or heat pump. Note the SEER2 is updated version of rating system for new units manufactured in year 2023 and after, here we used SEER instead of SEER2 as insufficient data for the updated version.

package and the measure packages in the NREL efficiency upgrade simulation data.[51] The efficiency scenarios informed estimated heating load reductions of roughly 1.2% annually for residential buildings and 0.6% for commercial buildings through 2050. The impact of energy efficiency on cooling demand is discussed in section 4.2.3. and no additional adjustment is made to heat pump cooling profiles to avoid double counting.

The base case results presented in Figures 21 and 22 indicate that the peak winter heating electricity demand is due to heat pump adoption in the residential sector. The graphs below also show an overall decrease in peak day demand for each kind of heat-pump over years, which is mainly attributed to improved energy efficiency assumption that reduces energy footprint for heating. However, the reduction in share of PHPs over the forecast horizon causes the total impact from heat-pump adoption per customer (see Per EHP curve below) to increase.

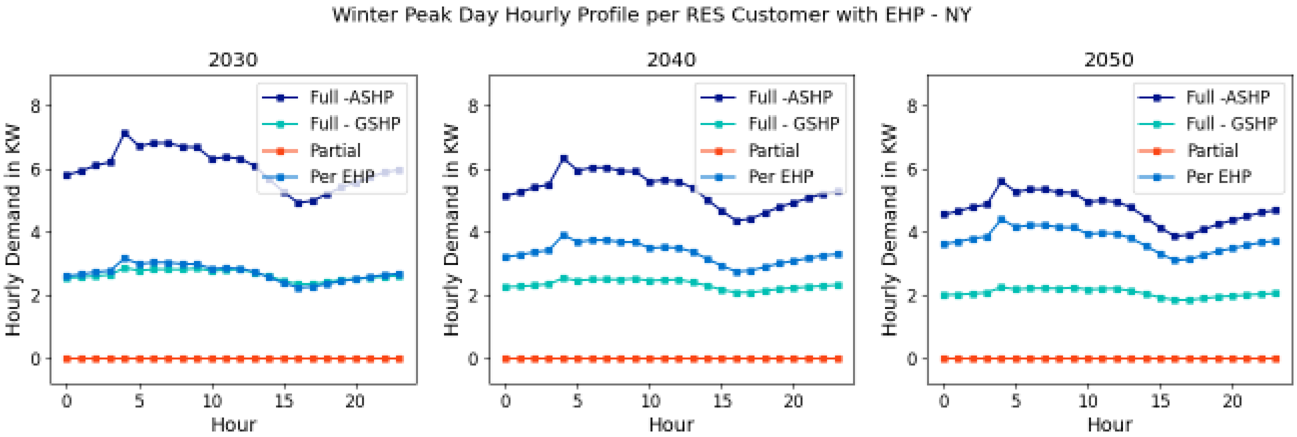

Figure 21: Winter Peak Day (selected years) Residential Heat Pump Profiles

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[51] The measure packages "1 - Basic enclosure" and "2 - Enhanced enclosure" are the two energy efficiency scenarios in the ResStock 2022 release. For detailed understanding of the upgrade packages "1 - Basic enclosure" includes and "2 - Enhanced enclosure" in the residential sector, see page 4, EUSS_ResRound1_Technical_Documentation (https://oedi-data-lake.s3.amazonaws.com/nrel-pds-building-stock/end-use-load-profiles-for-us-building stock/2022/EUSS_ResRound1_Technical_Documentation.pdf). Analogously, measure five packages from 2023 ComStock release that help determine the impact of energy efficiency are "6": "Exterior Wall Insulation", "7": "Roof Insulation", "8": "Secondary Windows", "9": "Window Film", "10": "New Windows".

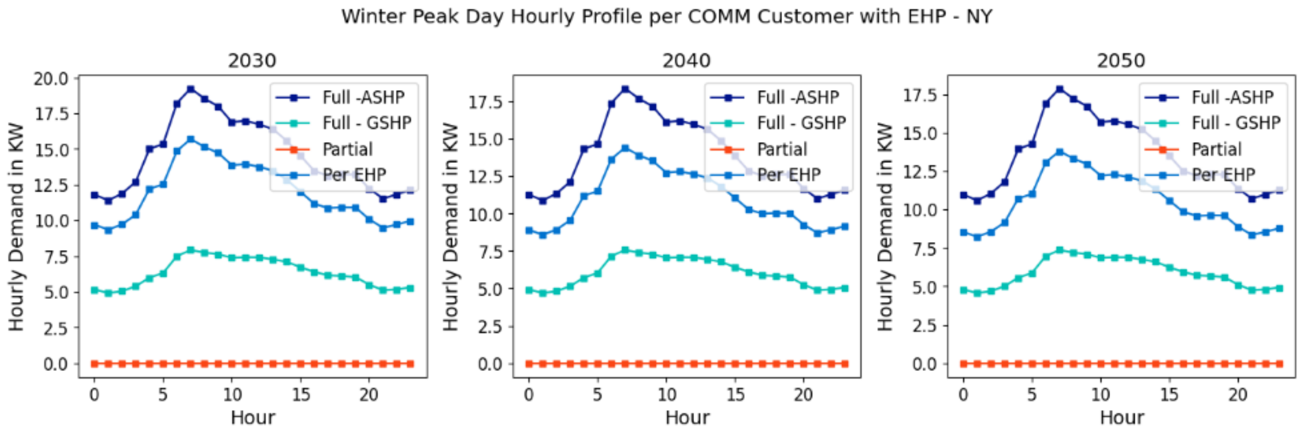

Figure 22: Winter Peak Day (selected years) Commercial Heat Pump Profiles

The base case results presented in the Figures 23 and 24 indicate that the peak summer cooling electricity demand due to heat pump adoption in the residential and commercial sectors. The heat pump cooling load here is additional load added to the grid, and the existing cooling load by traditional methods is subtracted from the heat pump cooling load to obtain the adjustments below.

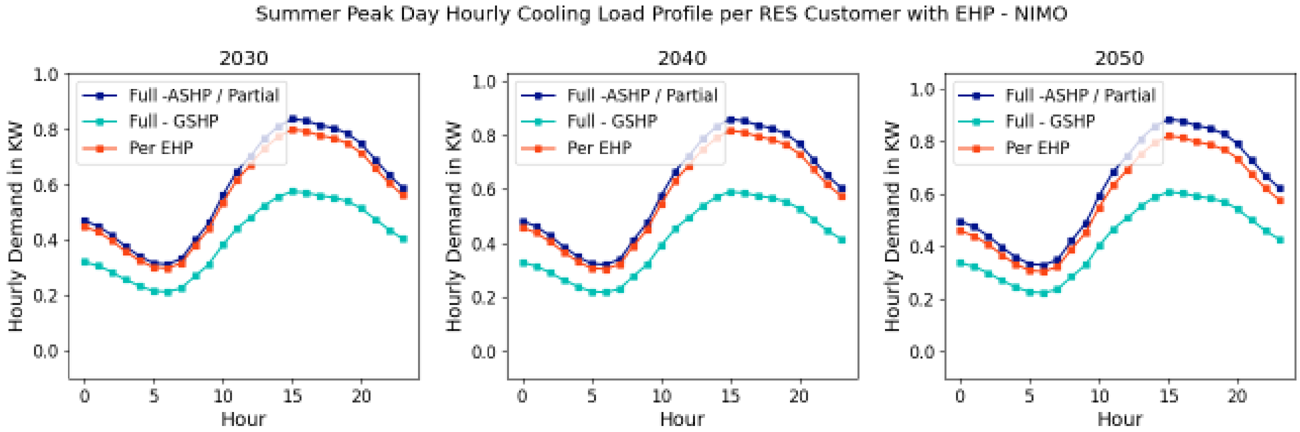

Figure 23: Summer Peak Day (selected years) Residential Heat Pump Profiles

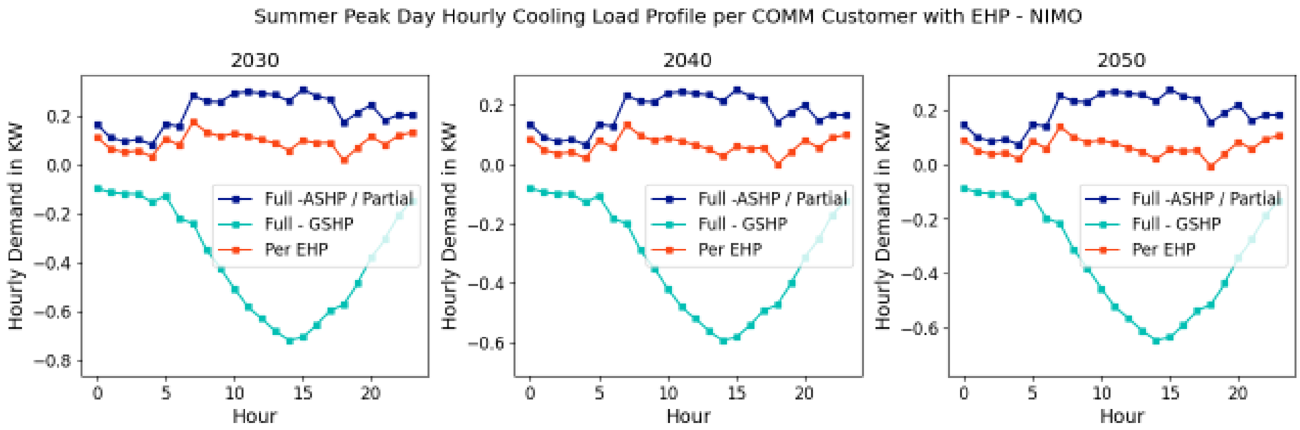

Figure 24: Summer Peak Day (selected years) Commercial Heat Pump Profiles

4.2.3. Energy Efficiency (EE)

System-Level Adoption Forecast

National Grid has operated EE programs in its New York service territory for several years and expects to continue these programs for the foreseeable future. Projections for year 2025, are based on planned EE savings in the approved company programs, as outlined in the New Efficiency New York Order.[52] From 2026 through 2030, EE projections are largely based on targets established in the Energy Efficiency and Building Electrification (EE/BE) Order, which prescribes a new strategic framework and eligible measures for program incentives.[53] From 2030 to 2042, incremental EE savings are expected to remain flat and starts showing a decline from 2043 onwards. However, planned EE savings from 2026 onward have been adjusted upward to account for savings from building code enhancements and potential savings occurring outside of company programs from non-incentivized measures, such as lighting.[54] As a result of the new strategic framework, the forecasts show a significant reduction in EE savings after 2025, driven by the shift toward more costly measures with longer useful lives, the phase-out of traditional savings sources, and an increased allocation of funding toward building electrification and weatherization. Figure 25 shows the cumulative EE projections by customer groups.

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[52] Case 18-M-004.

[53] CASE 18-M-0084 & Case 14-M-0094

[54] The company leveraged building stock data published by the National Renewable Energy Laboratory (NREL) to estimate how electricity usage (non-heating end uses only; the impact of energy efficiency on heating is included in the heat pump profiles) by New York residential and commercial buildings changes as those buildings adopt various energy efficiency measures. If the potential energy efficiency savings estimated from NREL data are greater than the baseline energy efficiency savings assumed in the company's planned forecasts, adjustments were considered. From this analysis, additional adjustments were made for both residential and commercial sector.

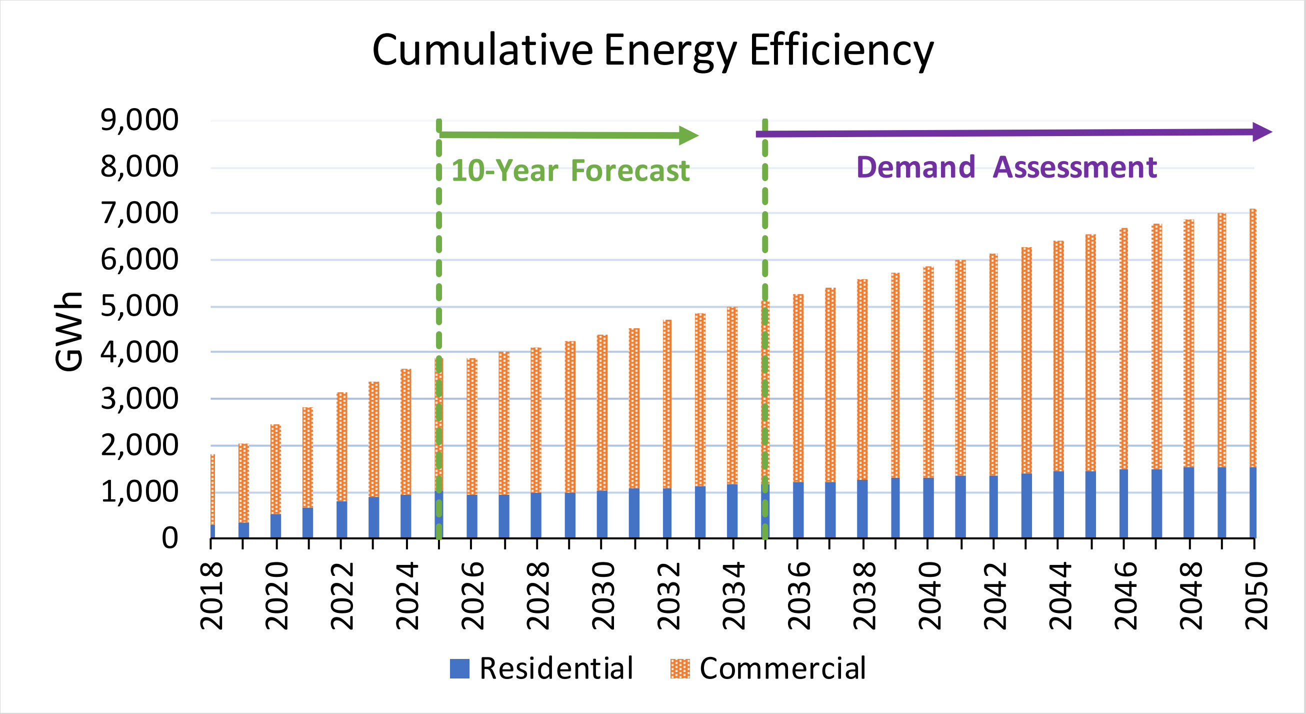


Figure 25: Cumulative Annual EE Savings (GWh) by Customer Class

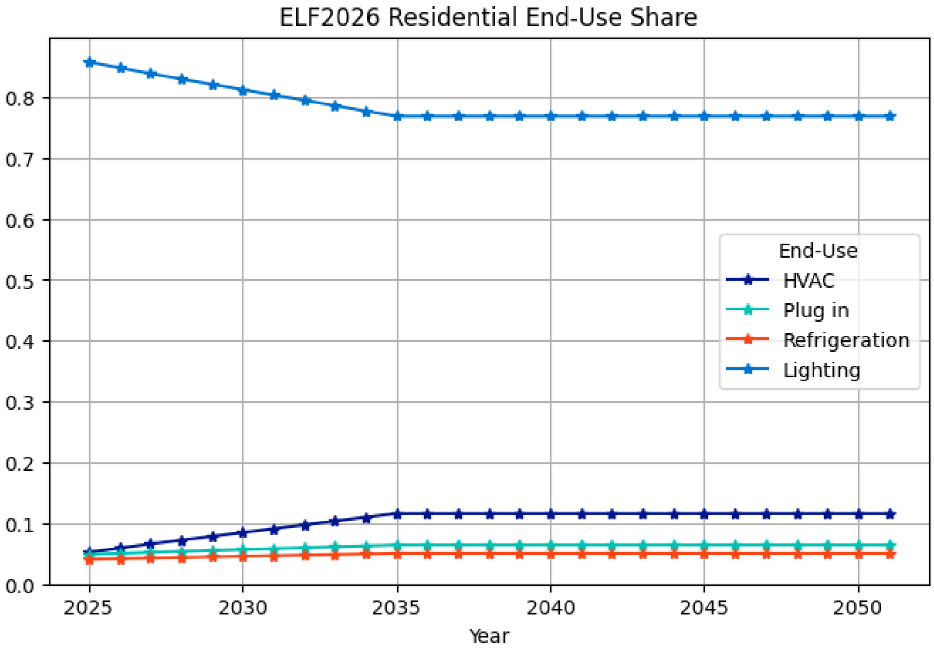
Feeder-Level Adoption Forecast

The annual, system-level energy efficiency (EE) savings are allocated to individual feeders in proportion to their residential and commercial energy consumption. This allocation approach reflects the assumption that a feeder's potential energy-efficiency savings are correlated with its overall electricity usage. In general, feeders with higher annual consumption are assumed to serve customers with a greater number of electric end-use devices, larger loads, or buildings that are more energy-intensive in nature. As a result, these feeders present more opportunities for savings through participation in EE programs, whether through equipment replacements, building-shell improvements, or adoption of higher-efficiency technologies. Allocating EE savings based on consumption therefore ensures that expected savings are distributed in a manner consistent with both the existing load characteristics of each feeder and the likely distribution of future efficiency improvements.

Profiles

The Energy Efficiency profile was derived by analyzing NREL's End-Use Load Profiles (EULP) for the U.S. Building Stock Data, covering both residential and commercial buildings. The data provides 15-minute energy consumption load profiles, simulated for all major end uses by building types across the country. The EULPs reported on buildings in the state of NY are converted into hourly profiles and used to construct the EE profile.

Four primary end-use categories were considered in the modeling of the Energy Efficiency profiles: lighting, HVAC, refrigeration, and equipment/plug-in appliances[55]. Each of the end-use profile was weather normalized independently and then combined into one single profile by taking weighted average based on end-uses share. The end-use shares are obtained from historical actual EE savings and projected savings in the Company's EE plans. The profile is normalized by dividing each hour's value by the total annual value, so that each hour represents its share of the year's total savings. For both residential and commercial sectors, lighting has remained a dominating source of EE savings due to its large share historically which cumulates over time. See detailed end-use shares assumed for each year in Figure 26. The peak day profiles are plotted in Figures 27. In the winter, the residential peak happens at 8pm and commercial is at 12pm, both are driven by savings from lighting programs. For summer, the residential peak hour happens at 8pm which is driven by cooling and lighting program savings. In the commercial sector, the peak is at hour 12pm which is result of both lighting and cooling programs as well.



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[55] Energy efficiency saving from heating is modeled in the electric heat pump profile.

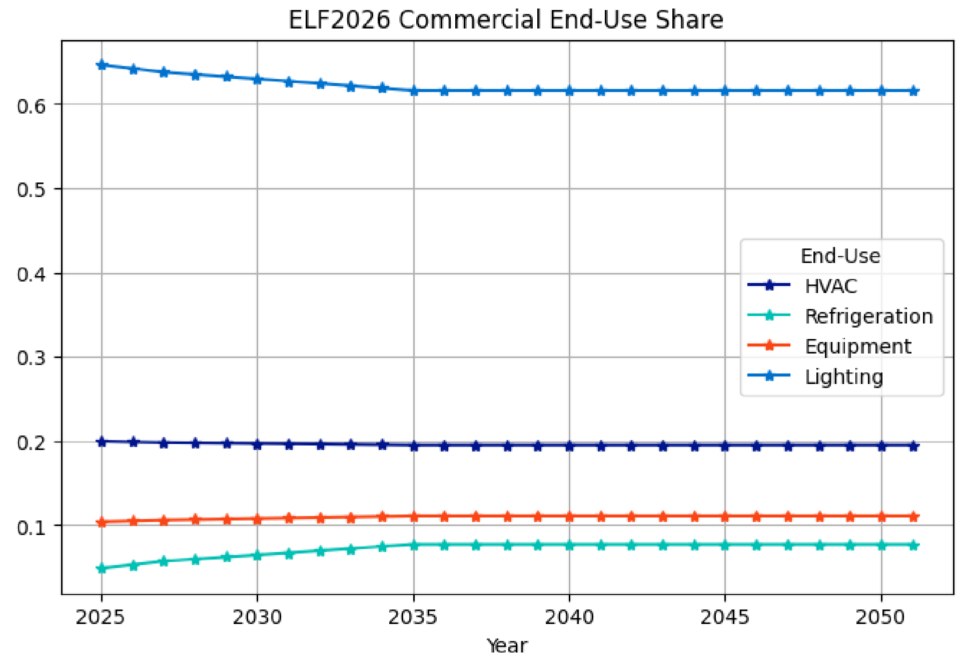

Figure 26: End-Uses Share

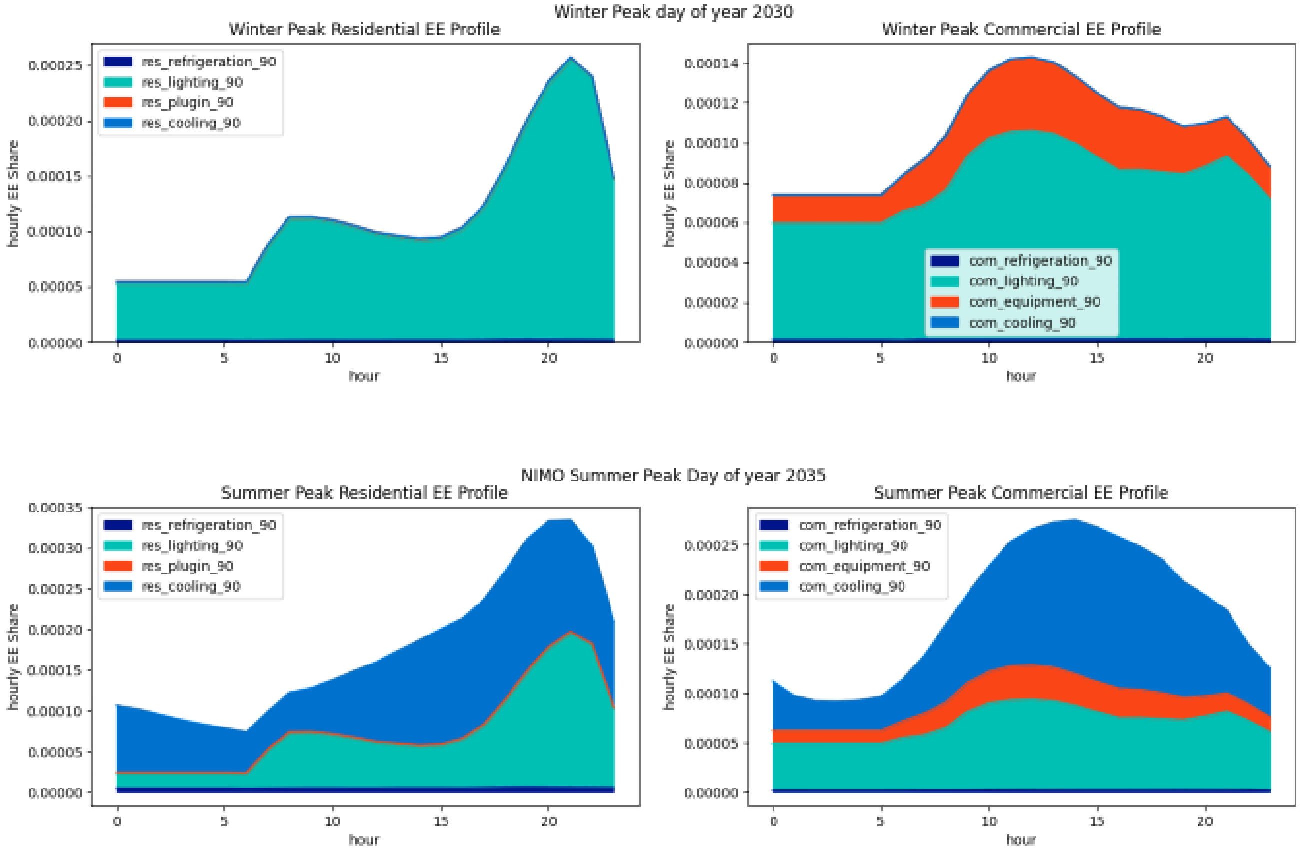

Figure 27: Winter & Summer Peak Day EE Profiles

4.2.4. Solar-Photovoltaic (PV)

System-Level Adoption Forecast

Historical connections of PV are tracked by the Company. Projected annual connections in the first forecast year are based on the historical rate, estimated realization of queued projects, and subject-matter expert (SME) consensus. For 2026 and beyond, projections are tied to the Additional Action scenario from New York's Draft State Energy Plan, which includes zonal breakdowns of the state-wide installation target for PV capacity of 10,000 MW in 2030.[56][57]

The forecast assumes the Company's share of the state-wide Zone A-E target (4,476 MW in 2030) is 51% and Zones F's target (1,165 MW in 2030) is 93%. Note, the targets in the Additional Action scenarios plateau after 2030 but the PV capacity projections still show minimal growth until 2050.

Figure 28 shows the projected cumulative connected PV installations of the Company's New York jurisdiction. As of 2024, it is estimated about 1,895 MW has connected, which is projected to grow to 3,767 MW by 2035 and 4,093 MW by 2050.

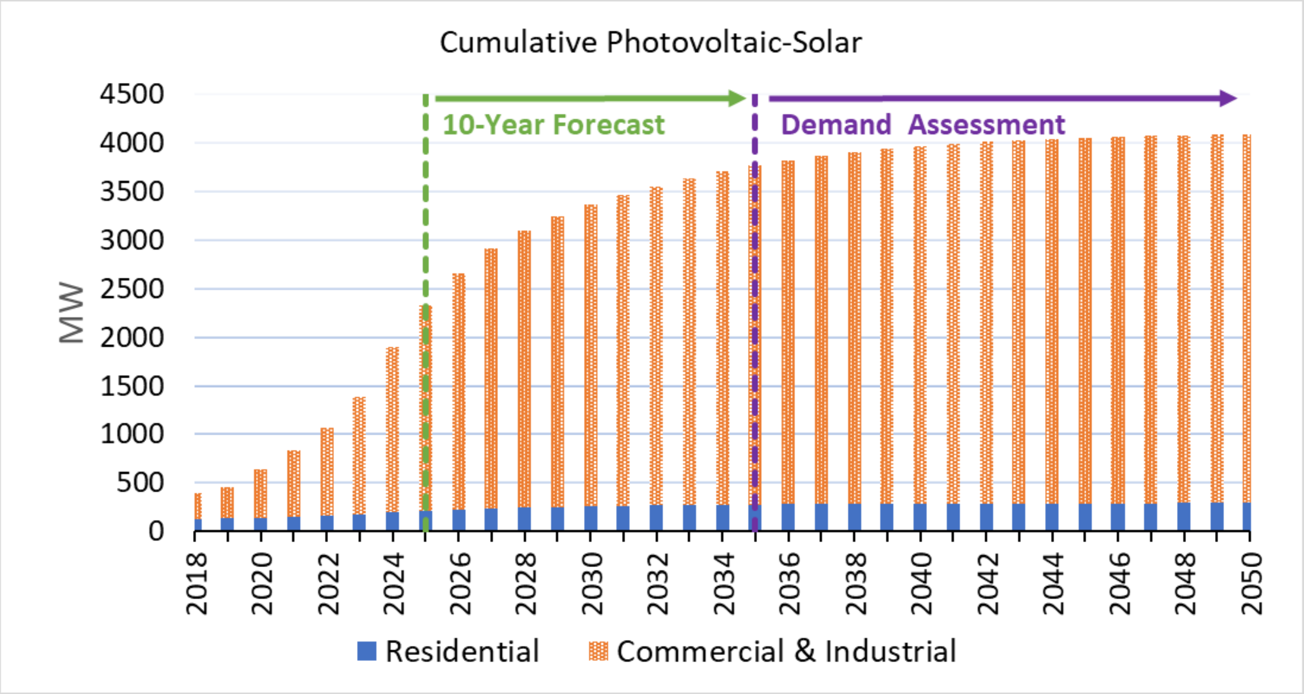

Figure 28: Cumulative Annual Solar PV Connections

Feeder-Level Adoption Forecast

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[56] https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B6094AD89-0000-C134-AEF9-4685F6C3B7F2%7D#:~:text=The%20April%202022%20Order%20adopted,the%20incremental%204%2C000%20MW%2Ddc.

[57] https://energyplan.ny.gov/Plans/2025-Energy-Plan

Feeder-level PV projections are allocated into three types of PV technology: residential rooftop, commercial rooftop, and non-rooftop systems.

Residential Rooftop PV

The system-level annual incremental projection is first allocated to projects in the residential application queue until the queue is used up. Then, the remaining incremental is allocated to feeder-level using a top-down approach. A propensity model based on socio-economic and consumption variables including, but not limited to household income, mortgage values, and annual energy usage is utilized to rank feeders in the territory by projecting their likelihood of adopting rooftop PV. For example, feeders that exhibit a higher share of high-income, single-family homeowners are more likely to adopt. All the feeders are scored and ranked by the scores from most likely to least likely adopters of rooftop PV. Then, allocation weights are determined by taking the product of feeder customer count and the ranking. Finally, the system level projections are allocated proportionally to feeder weights. Feeders with high propensity and high customer counts will receive a larger share of allocation compared to a feeder with low propensity and low customer count.

Commercial Rooftop PV

The commercial rooftop share of system-level incremental projection is derived from the historical share of commercial connected systems. The system-level annual incremental projection is allocated to commercial projects in the application queue. Then the remaining incremental is allocated to feeder-level by using a top-down approach. A simple return-on-investment (ROI) calculation based on customer consumption and rooftop availability is utilized to estimate commercial customer's potential nameplate and relative financial rank of such system. All commercial customers with roof space for solar system development are scored and ranked from highest financial potential to lowest. Then the commercial rooftop share of system-level projection is allocated to the highest customers each year until system level projection is met.

Non-Rooftop PV

For the near term, the non-rooftop PV nameplate projection is based on projects in the application queue and their estimated connection date. The annual aggregated incremental nameplate connection is bounded by the system-level projection.

In the long term, the system-level annual incremental projection is allocated to the available and suitable land parcels that are most likely to develop PV. Available and suitable land parcels are ranked by their likelihood to develop PV and then the system-level projection is allocated to the highest ranked parcels each year until the system-level projection is met. The Company leverages the renewable interconnection analysis tool developed by GridTwin[58] for analyzing land parcel availability and suitability, and ranking PV projects. The GridTwin tool considers land suitability (for developing PV projects) based on land use codes, environmental and cultural restrictions, as well as land characteristics (e.g., slopes). It ranks available and suitable land, by calculating the Internal Rate of Return (IRR) to

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[58] https://home.gridtwin.com/

rank the profitability of developing PV projects on each land parcel. The cost components considered in the IRR calculation include land cost, interconnection cost, capital cost, and annual operation & maintenance costs. PV potential of overhead vs underground connections are also considered in the interconnection cost. The highest-ranking parcels are allocated with corresponding capacities to the closest feeder.

Profiles

The photovoltaic (PV) generation profiles are developed using simulated PV output from NREL's PVWatts tool. The tool is built on an advanced physical model created by NREL, designed to simulate the electrical output of Solar PV systems based on specified system configurations and weather inputs. The Company considers two system configurations to capture diversities in system configuration across its service territory[59]: (1) fixed PV; (2) one-axis tracking PV. For both systems, other configuration parameters (e.g. Inverter Efficiency, System loss, etc.) use NREL's default parameter setting. The weather inputs align with the temperature-focused weather scenario selected from the Baseload process and uses that to identify range of possible corresponding irradiance terms, including Global Horizontal Irradiance (GHI), Diffuse Horizontal Irradiance (DHI) and Direct Normal Irradiance (DNI)[60] that are critical factors impacting solar PV generation.

The irradiance profiles, along with other weather variables' profiles, are then fed into PVWatts to generate a range of simulated PV generation under the identified weather samples. Then, the median is taken from the distribution which reflects a representative profile. Figure 29 presents month-hour average PV performance heat map for Solar PV. The PV generally produces more energy around noon and matches the sunrise and sunset hours.

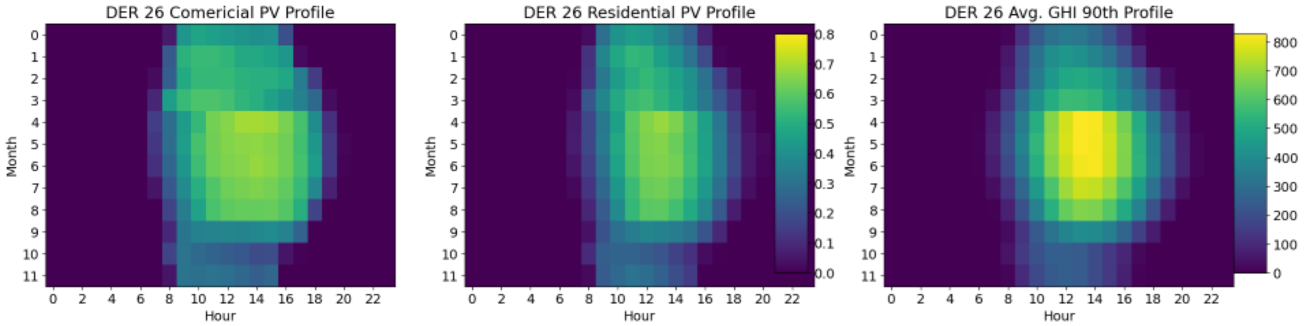

Figure 29: Annual Solar PV Performance

4.2.5. Energy Storage (ES)

System-Level Adoption Forecast

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[59] PVWatts Technical Manual, https://www.nrel.gov/docs/fy14osti/62641.pdf, NREL

[60] Diffuse horizontal irradiance (DHI) is the radiation at the Earth's surface from light scattered by the atmosphere. Direct normal irradiance (DNI) is measured at the surface of the Earth at a given location with a surface element perpendicular to the Sun direction. Global horizontal irradiance (GHI) is the total irradiance from the Sun on a horizontal surface on Earth. It is the sum of direct irradiance (after accounting for the solar zenith angle of the sun) and diffuse horizontal irradiance.

Historical ES interconnections are tracked by the Company. In the first forecast year, annual ES connections are based on historical trends, expected realization of queued projects, Subject Matter Expert (SME) consensus, and achievement of New York State ES targets. These targets assume rapid deployment of ES projects, reaching at least 6 GW of installed capacity by 2030.[61]

The Company's ES projections through 2030 are based on the trajectory needed to meet these state targets. To translate statewide targets into Company-specific forecasts, the Company relies on New York's Draft State Energy Plan Additional Action scenario, which represents a pathway in which the State's ES targets are achieved in 2030.[62] The zonal allocations from this scenario are used to disaggregate statewide ES targets into ISO zones. The Company share is assumed to be 51% of Zone A-E and 93% of Zone F. Post-2030, ES projections continue to follow the trajectory implied by the Additional Action scenario through 2050.

These state targets represent total ES capacity that could be connected to either the transmission or distribution systems. However, the base-case projections assume that most future ES capacity will consist of large, transmission-connected batteries that operate as supply-side resources and therefore do not affect customer demand on the Company's distribution system. Accordingly, the forecast assumes that 24% of state-targeted ES capacity impacts the distribution system in the early years, declining to 17% by 2050.

Figure 30 shows the projected cumulative connected ES capacity of the Company's New York jurisdiction. As of 2024, it is estimated about 119 MW of capacity has connected, which is projected to grow to about 438 MW by 2035 and 858 MW by 2050.

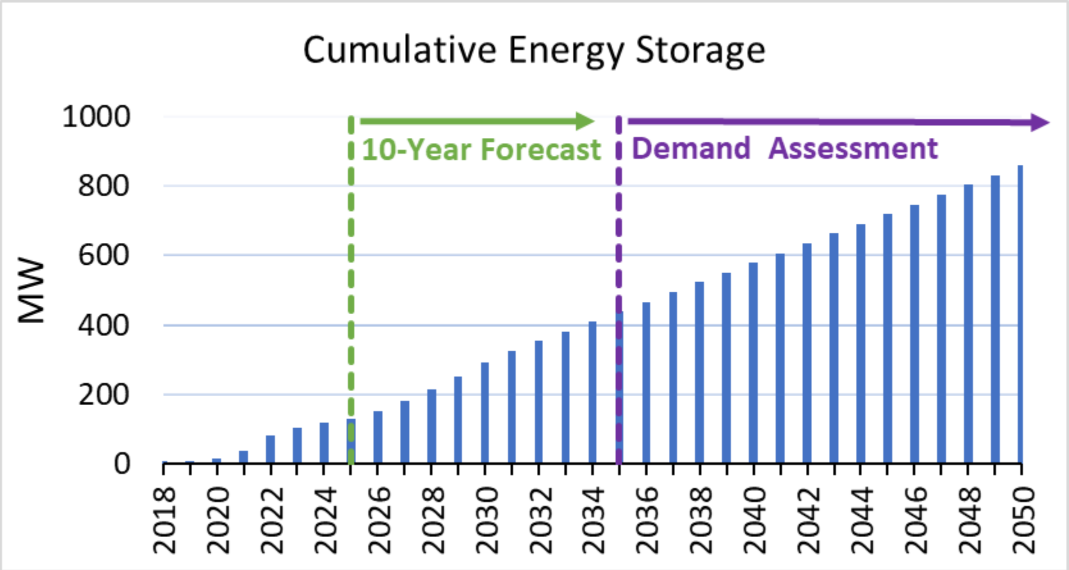

Figure 30: Cumulative Annual Energy Storage (MW Nameplate Capacity)

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[61] https://www.nyserda.ny.gov/-/media/Project/Nyserda/Files/Programs/Energy-Storage/2024-06-6GW-Energy-Storage-Order.pdf

[62] https://energyplan.ny.gov/Plans/2025-Energy-Plan

Feeder-Level Adoption Forecast

In the first phase of allocation, the system-level annual incremental is allocated according to the application-queue and their estimated connection date. Once the application queue is used up, feeder-level allocations assume to be co-located with ground-mounted PV systems identified using the Gridtwin tool in order of their IRR rank. The nameplate capacity of the storage systems is assumed to be equivalent to the storage nameplate capacity, consistent with recent historical connections.

Profiles

An hourly profile was developed to allocate the ES capacity described above to each hour of the year. Reliable data on actual energy storage usage was not available to develop these profiles. Instead, SME knowledge, proposed ES program discharge times, and assumed customer behavior from different battery configurations were used to develop the final weighted profiles.

SMEs created four base profiles for different battery configurations in each season and for each customer class. The base profiles combinations are:

A. Peak Reducing, Solar-Paired: Customer's batteries are solar-paired and discharge during defined peak hours in the evening.

B. Peak Reducing, Non-Solar: Customer's batteries charge from the grid or are paired with non-solar distributed generation source, and discharge during defined peak hours in the evening.

C. Non-peak Reducing, Solar-Paired: Customer's batteries are solar-paired and will not necessarily discharge during defined peak hours in the evening.

D. Non-peak Reducing, Non-Solar: Customer's batteries charge from the grid or are paired with non-solar distributed generation source and will not necessarily discharge during defined peak hours in the evening.

Commercial and industrial (C&I) batteries are assumed to be able to discharge over a four-hour period, while residential batteries are assumed to be able to discharge over a two-hour period. The peak-shaving factor represents the percentage of total battery capacity assumed to be available for discharge during peak periods. Solar-paired C&I batteries are assumed to have an 85% peak-shaving factor, while non-solar-paired C&I batteries that charge from the grid are limited to 50% of their total discharge capacity. Residential batteries are assumed to have a peak-shaving factor of 85%.

In NY, peak reducing and non-peak reducing customers are assumed to discharge and charge during the same hours. The discharge windows represent both the Company's proposed timeframe for peak reducing discharge and the assumed behavior of customers who do not necessarily target peak reduction. Charging behavior depends on if the battery is paired with solar.

The final profiles for each season, categorized by solar-paired and non-solar-paired configurations, are created by weighting the base profiles according to customer class and peak reducing behaviour. These profiles are shown in Figure 31.[63] Historical connections in the Company's distributed generation database and SME's market knowledge are used to determine the weight of residential/commercial installations and peak reducing behaviour. 5% of all annual ES capacity connections are expected to be from residential batteries and the remaining 95% are commercial/industrial batteries in the forecast period. 50% of the annual ES capacity for both residential and commercial/industrial is expected to be peak reducing.

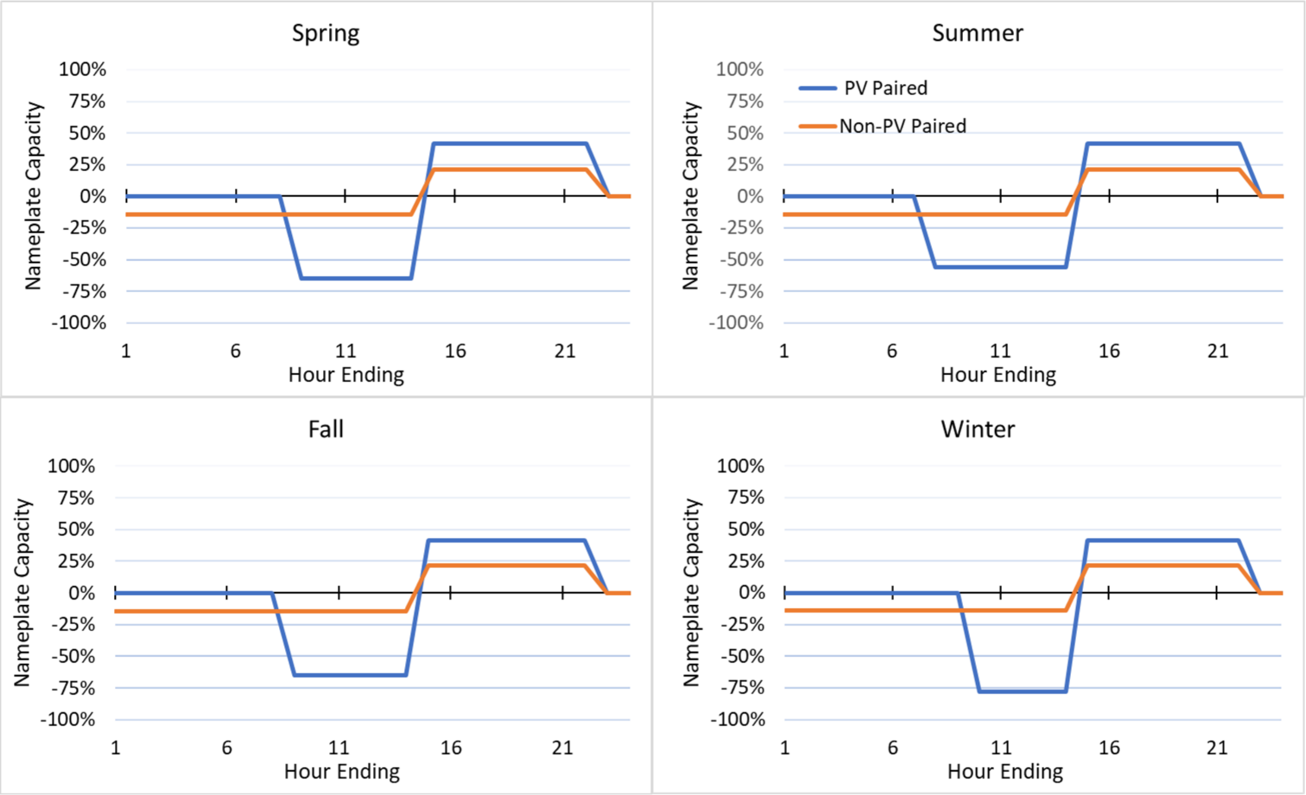

Figure 31: Weighted Profiles by Season

For storage systems in a DC-Coupled configuration, the storage charging profile is limited to the total available PV generation for the feeder. In addition, the discharge profile is limited to the available state of charge after charging is complete.

4.2.6. Demand Response (DR)

System-Level Adoption Forecast

DR programs target reductions to peak demand during hours of high expected demand and/or reliability concerns, reducing the need for costly infrastructure investments. In this way, demand response programs enable utilities and operating areas, such as the New York Independent System Operator

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[63] The weighting between solar-paired and non-solar paired projects is done using Feeder-level results.

(NYISO), to act in response to a system reliability concern or economic (pricing) signal. Unlike energy efficiency programs, which provide passive savings throughout the year, demand response resources must be actively dispatched, with an associated event declared. During these events, customers can participate by either cutting their load or by turning on a generator or storage system from behind the customer's meter to displace their usual load.

In general, there are two categories of DR programs in New York: NYISO DR programs and Company retail-level programs. The NYISO programs, referred to here as "wholesale DR", have been active for several years and are periodically activated. The company's policy has been to add back the reductions from these wholesale DR events to its reported system peak numbers so that the system peak numbers more accurately reflect what they would have been in the absence of the NYISO events. This is because the Company is not in control of the dispatch days or times for NYISO events, and thus there is no guarantee that these NYISO events would align with the Company's peaks. Therefore, the Company must plan under the assumption they are not dispatched to ensure peak load adequately reflects how big system-level load could be. Alongside the wholesale demand response programs, the second set of DR programs are those run by the Company at the retail customer level, including a thermostat program for residential customers[64] and several available programs for commercial and industrial customers.[65] Most notable among these is the Commercial System Relief Program (CSRP), since this program includes two types of participants that are treated differently in the forecast. One category includes those customers who are also enrolled in NYISO's Special Case Resources (SCR) DR program. Per the Tariff with the NYISO, these are considered as "supply-side" resources and are not included as load reductions to the forecast. In contrast, the other customers (i.e., those not enrolled in the SCR program) are included in the forecast as a summer peak load reduction, because the Company has full control of these resources. [66]

In 2025, for NIMO, the estimated DR impact on summer peak was 25.7 MW (in the retail program only) and is expected to grow to about 50.6 MW by the end of the forecast horizon and 88.1 MW by the end of the load assessment period.[67] This increase primarily reflects growth in the residential customer thermostats program, in line with recent historical trends and long-term program participation expectations. Meanwhile, the impacts from C&I programs are held flat through the forecast, consistent with near-term program expectations and recent history. Although not explicitly modelled, the hours of dispatch for DR events are assumed to move over time as necessary to overlap summer peak loads.[68] Lastly, note that DR impacts are not evaluated at more granular geographic levels due to a lack of

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[64] See https://www.nationalgridus.com/Upstate-NY-Home/ConnectedSolutions/ConnectedSolutions-Electric

[65] These include a Commercial System Relief Program (CSRP), a Term Dynamic Load Management (Term-DLM) program, and an Auto-DLM program. The CSRP program was called several times in the past year and is dispatched any time the projected next day loads are expected to reach 92% of the company's 95/5 extreme weather peak forecast, as per a regulatory agreement with the PSC. For additional background on the programs, see the following resources: https://www.nationalgridus.com/media/pdfs/bus-ways-to-save/ee7015-csrp-flyer.pdf; https://www.nationalgridus.com/media/pdfs/bus-ways-to-save/term-dlm_-brochure_final.pdf; https://www.nationalgridus.com/media/pdfs/bus-ways-to-save/auto-dlm_-brochure_final.pdf

[66] These DR forecasts only impact summer peaks as there are currently no winter DR programs for the electric business. Additionally, note that while the Company does have battery storage DR programs, these impacts are not included here in to avoid double counting, as battery storage impacts are reflected in the energy storage adoption forecasts and profiles.

[67] Historical data is based on actual event performance data and can vary meaningfully year to year due to weather and behavioral effects.

[68] As peak hours move outside of normal windows for commercial operations, DR impacts may become harder to achieve, potentially reducing long-term growth.

granular level data for conducting this analysis.[69] See Figure 32 below for the relative contribution and cumulative summer peak load impact across the residential and commercial DR programs through 2050.

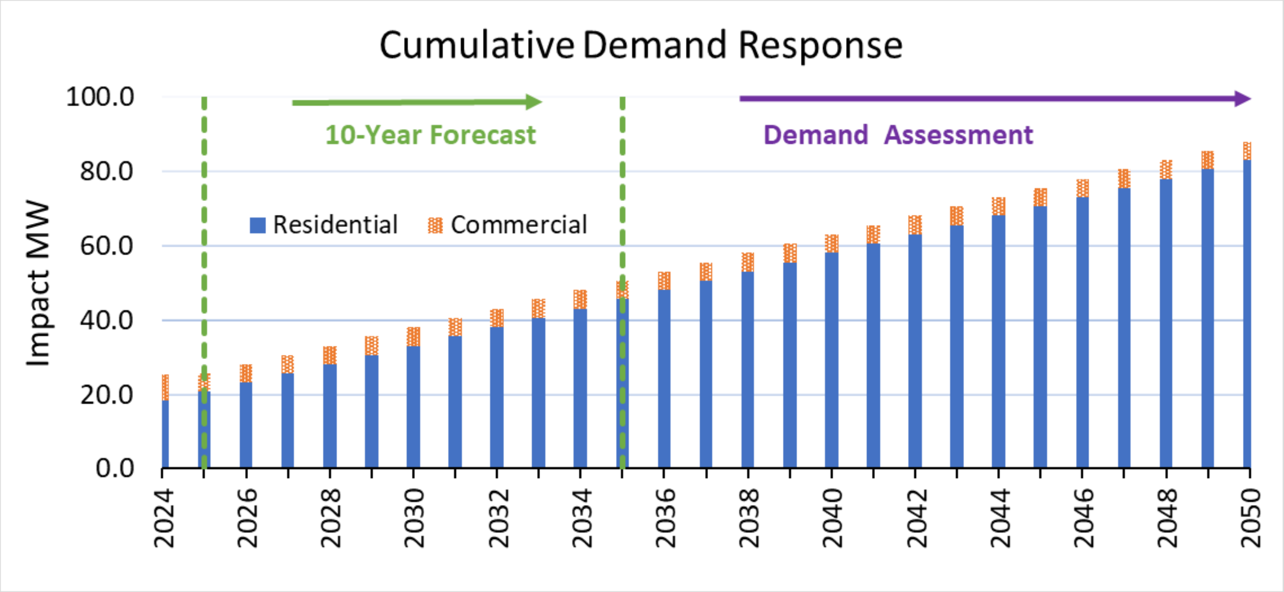

Figure 32: Cumulative Summer Peak Impacts

Profiles

The system-level impacts reflect reductions at the summer peak hour, but there are other relevant load impacts that need to be modelled around the specific peak hour impacts. For instance, customers may pre-cool their house leading up to an event or a commercial customer may turn back on systems after an event is over, both of which can lead to a bounce back in usage. Depending on the timing and extent of these behaviors as well as interactions with other DER technologies, it is possible the peak hour may shift to before or after the DR event window. This makes it as important to capture the dynamics around the peak hour as it is to model the peak load reduction. Thus, demand response profiles are generated for the entire peak and are defined in relative terms to the maximum event-window peak reduction, which receives a value of one. Under this framework, positive values indicate a load reduction while negative values indicate a load increase. For the C&I programs, profiles are estimated based on actual performance data from NY C&I DR events. For the residential program, historical performance data from the Company's thermostat DR programs on the gas side are used to build relative profiles.[70]

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[69] When more granular information becomes available (e.g. AMI data), the Company may revisit this topic.

[70] Due to differences in peak load timing between gas and electric, the relative profiles are shifted so that peak reduction falls later in the day, to better align with the peak hour window typically targeted by the Company's residential electric-side thermostats program (i.e., late afternoon to early evening versus morning on gas side).

4.3. Feeder to Zonal Aggregations

To assess the impact of Distributed Energy Resources (DERs) on zonal load, we employ a process of aggregation from the feeder level to zonal levels. It is a one-to-one mapping from feeder to ISO zones. All feeders under the same ISO zone are aggregated to create the zonal level value. We then integrate the DER profiles outlined above to derive the impact of zonal DER load. Those DER projections are subsequently applied to the baseload forecasts, enabling us to generate net load forecasts for each zone in the NIMO service territory.

5. Integrated Results

The integrated results refer to the netload after adjusting the predicted Baseload for DER impacts. The subsections below present and discuss the netload from different perspectives.

5.1. Seasonal Peak Load

Figure 33 shows NIMO's forecasted seasonal 90th peak load before and post DER impacts. The annual peak is expected to occur in the summer between 2025 and 2033. The peak hours will shift from late afternoon to evening/night hours. The Baseload is generally lower in the evening than the afternoon showing as a drop in years 2031, 2037, 2043 and 2046 in the summer Baseload and years 2037 and 2040 in the winter Baseload. Starting in 2034/2035 winter, NIMO's 90th winter peak is expected to become the annual peak mainly driven by the increasing load from electric heating and electric vehicle charging. Post the DER impacts, the CAGR of the annual 90th peak is expected to be 1.2% over the 10-year forecast horizon and 3.3% through 2050.

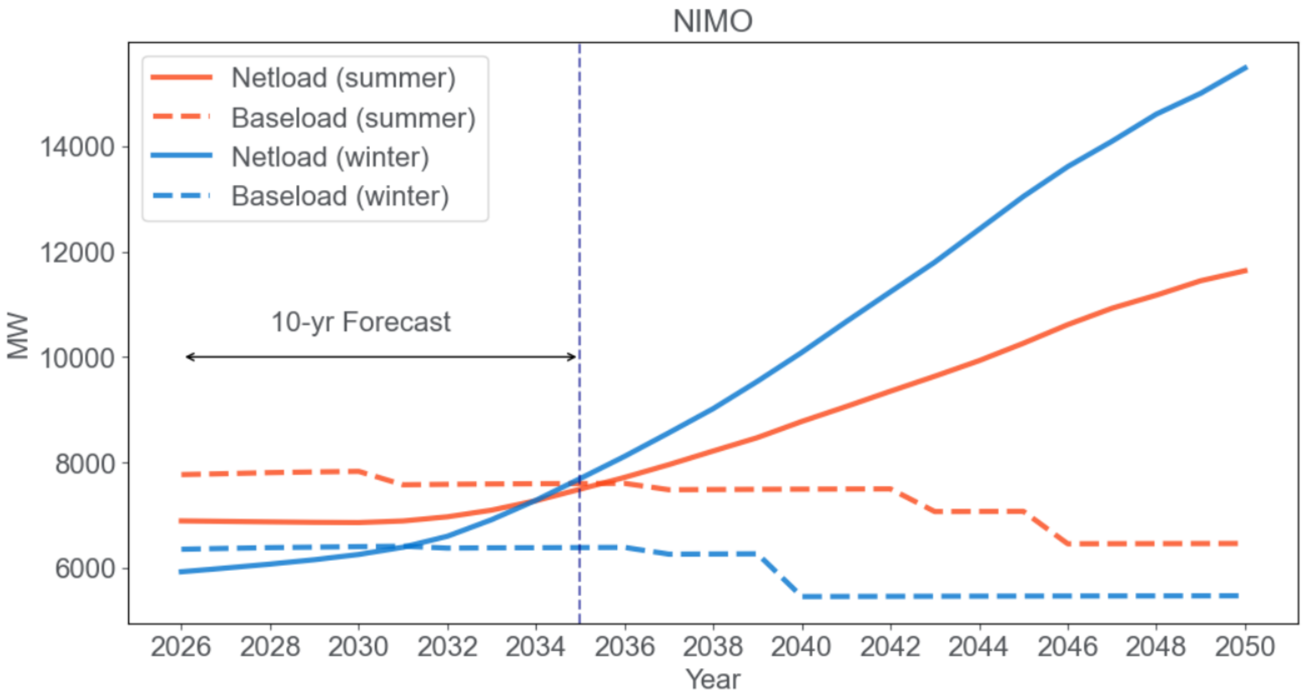

Figure 33: Seasonal 90th Peak Load before and after the impacts of DERs

Across the Company's service territory, Figure 34 below shows the annual CAGR (%) on a map by feeder where each marker represents the centroid of a feeder that is forecasted. In all, local growth is primarily driven by both the EV adoption growth and heating electrification. The median CAGR for all feeders in NIMO for 2050 assessment is 3.5%.

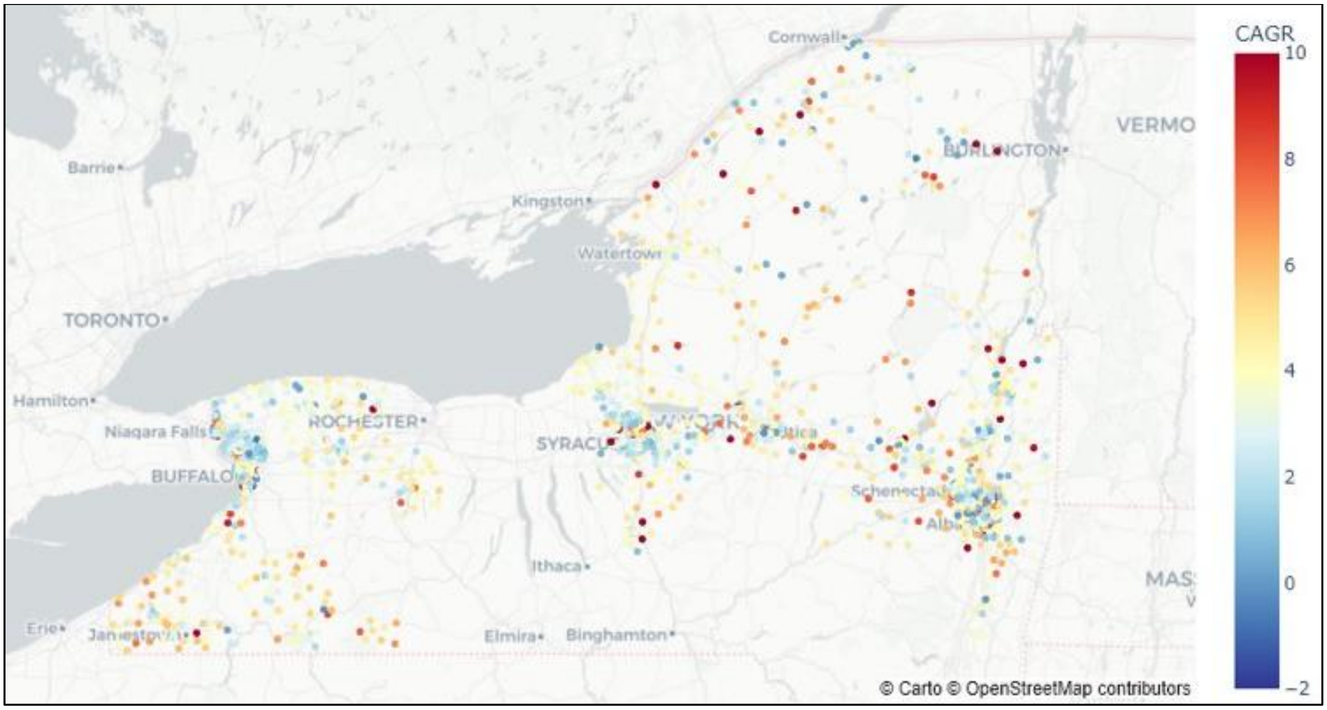

Figure 34: Spatial Map of Annual CAGR by Feeder

5.2. DER Impacts on Peak Load

Figure 35 presents the DER impacts at the 90th summer peak load time by DER technology and as the total net DER impacts. A negative value indicates load reducing impact and a positive value indicates load adding impact. EE impact steadily grows. PV becomes less impactful or unavailable as the peak moves into the evening/night hours. EV charging load is the primary load growth driving factor in later years. The net total DER impact turns from negative (i.e., load reducing) to positive (i.e., load adding) starting in the year 2035. Figure 36 presents the 90th summer peak load by components.

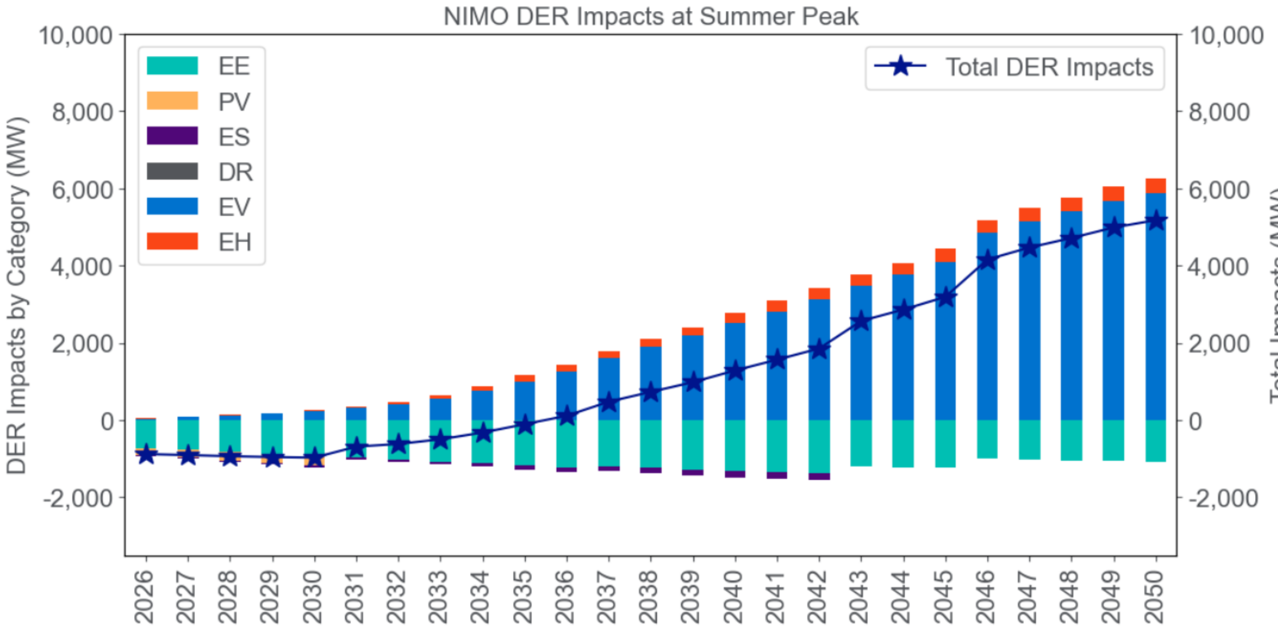

Figure 35: DER Impacts at 90th Summer Peak

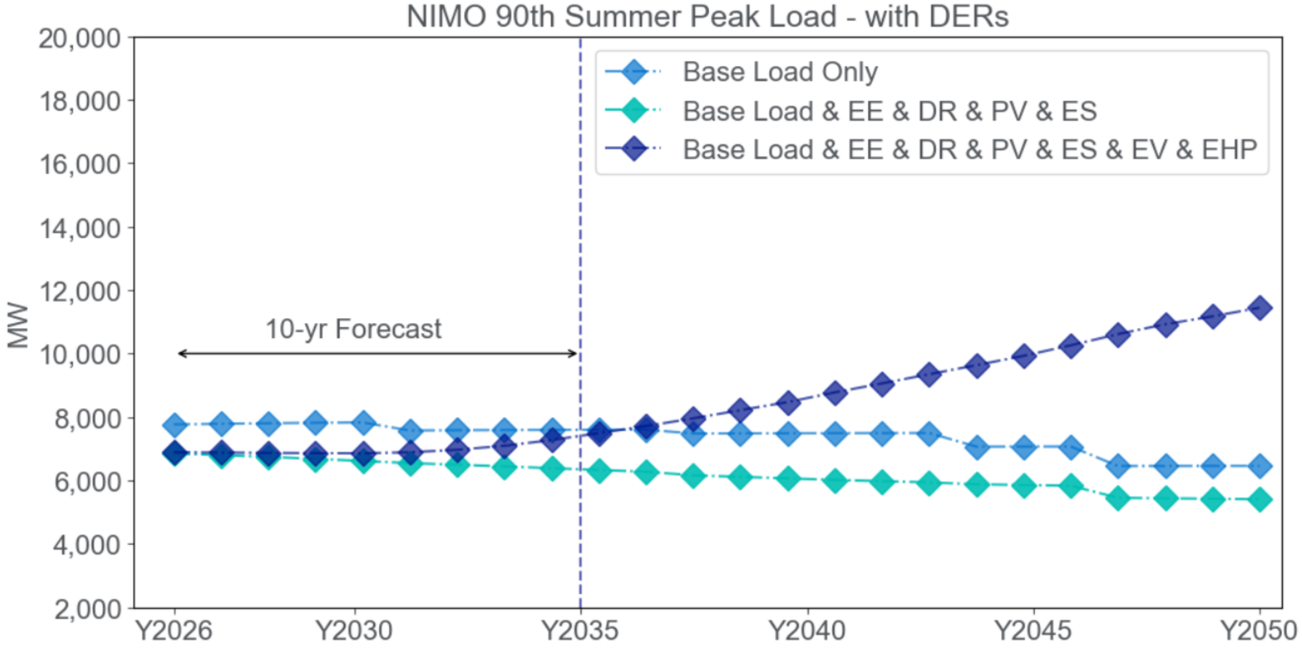

Figure 36: 90th Summer Peak Load by Components

Figure 37 presents the DER impacts at the 90th winter peak load time by DER technology and as the total net DER impacts. EE impact steadily grows but becomes slightly less achievable when the peak time moves into later in the night when the usage drops. PV is unavailable through the forecast horizon with winter peak hour always being after sunset. EV charging load and electric heating load are the primary drivers of load growth. The net total DER impact turns from negative (i.e., load reducing) to positive (i.e., load adding) starting in early 2030s. Figure 38 presents the 90th winter peak load by components.

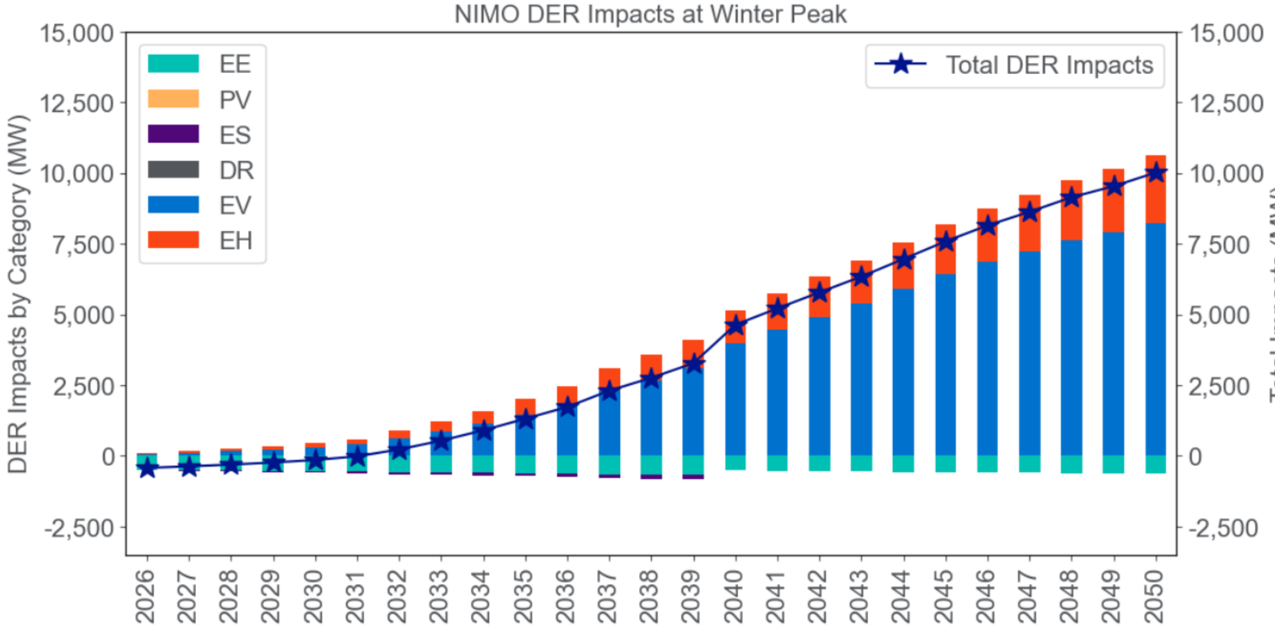

Figure 37: DER Impacts at 90th Winter Peak

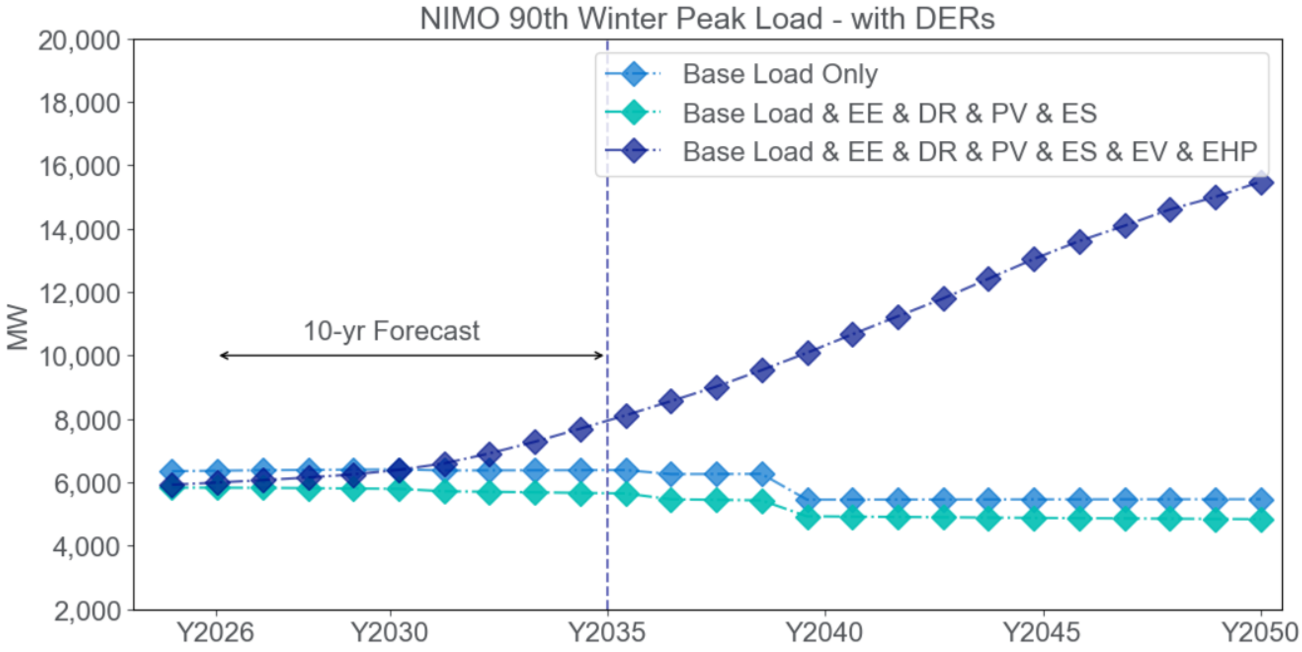

Figure 38: 90th Winter Peak Load by Components

5.3. Peak Day 24-hour Load Profiles

While the single peak values discussed so far are of major importance, the estimated impacts due to DERs on an hourly basis on these peak days is also important. This subsection discusses the seasonal peak day 24-hour load profiles. This allows the Company to look beyond the traditional approach of predicting only the 'single' highest seasonal system peak each year. The process now looks at the hourly load shape of all 24 hours of each peak day for each year of the planning horizon to determine the load and impact of DERs. This is useful to show the changing hours of the peaks as more DERs are added. For example, as more and more solar PV is placed on the system, the concept is that the summer peak hour will shift away from afternoon hours where solar irradiation is highest to evening hours as the solar reductions taper off. And as more electric vehicles chargers are installed, evening and nighttime loads can go up.

Figures 39 and 40 show the seasonal peak day profiles for Baseload (blue line), load after DERs that reduce load (orange line) and load after electrification load impacts (green line and red line). Over the horizon, the Baseload is more and more reduced by energy efficiency savings, PV generation (only available during daytime), ES discharging and DR (only available during summer peak window) throughout the day showing as the load curve being pushed from the blue line to the much lower orange line. Cooling load from using EH in summer and heating load from using EH in winter then push the load up to the green line. EV charging load shows as the biggest load growth driver for both seasons as shown by the red line.

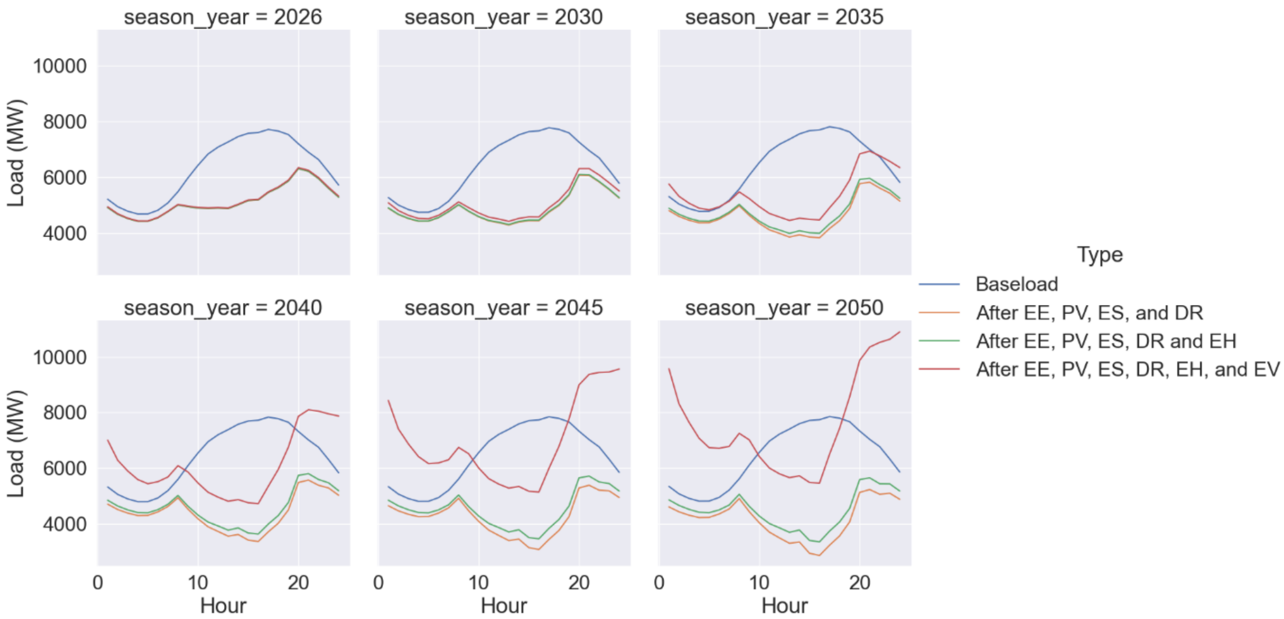

Figure 39: NIMO 90th Summer Peak Day Load Profiles

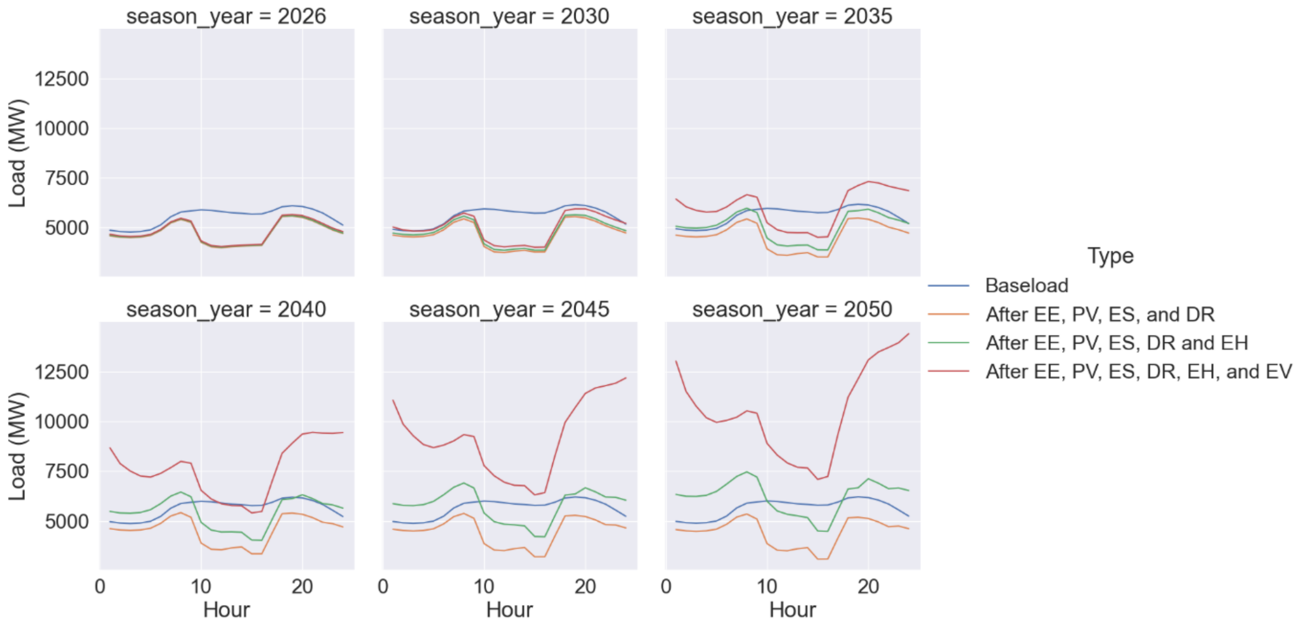

Figure 40: NIMO 90th Winter Peak Day Load Profiles

5.4. Winter Peaking Timeline

As aforementioned, the Company is expected to switch to a winter peaking system by year 2034/2035 under the 90th Baseload and Base DER scenario. Under the same scenario, the majority of the forecasted feeders are expected to switch to winter peaking by a similar time horizon as presented in Figure 41. The switching year will be slightly earlier in the 50th load and later in the 95th load and varies under different DER scenarios.

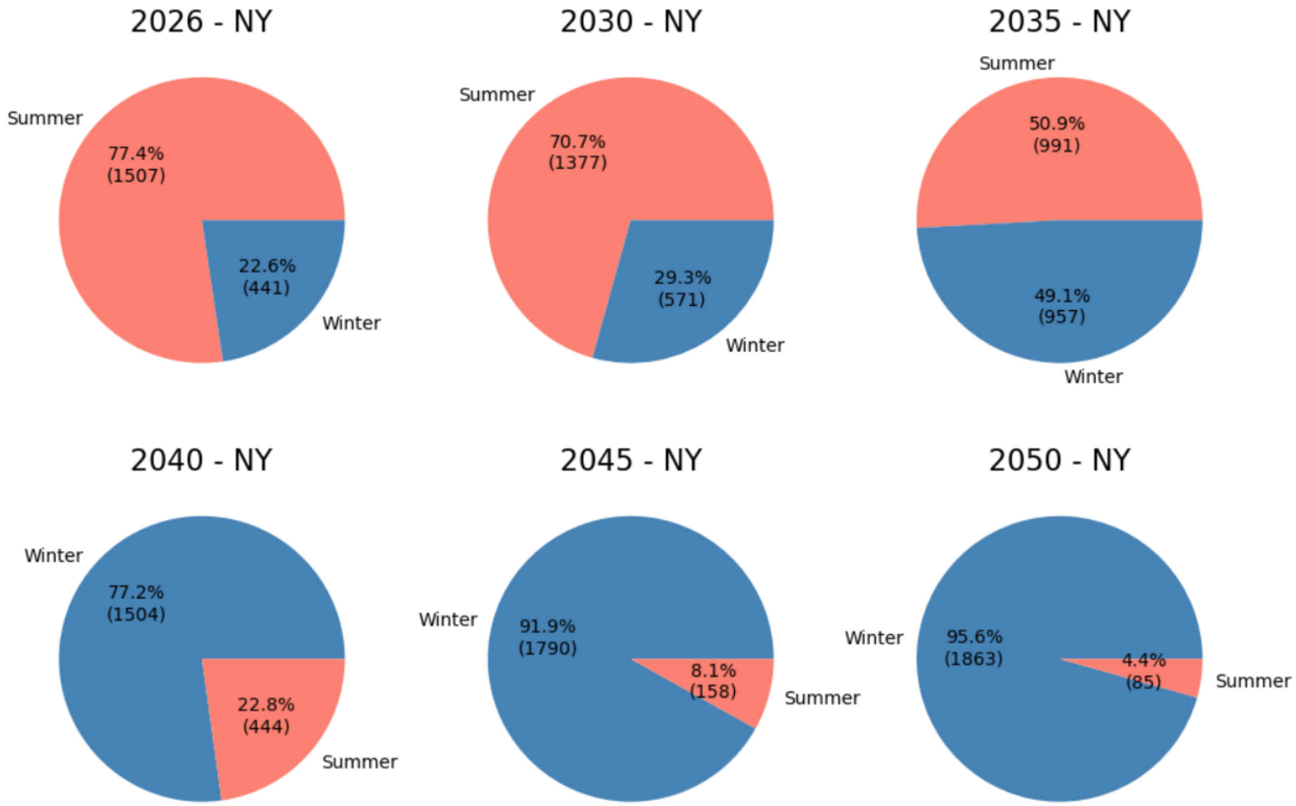

Figure 41: Share of feeder peak season for selected years

6. Comparison to the Last Release

Figures 42 and 43 provide a comparison of this year's summer 90th netload and DER impacts at the peak time to the prior forecast release. The summer 90th netload forecasts are slightly lower at the end of the 10-year forecast horizon in this release primarily from the lower EV projection and the refined EV profiles. The updated VMT assumptions overall present higher charging load impact for MDEV and lower impact for HDEV. The net impact is lower overall.

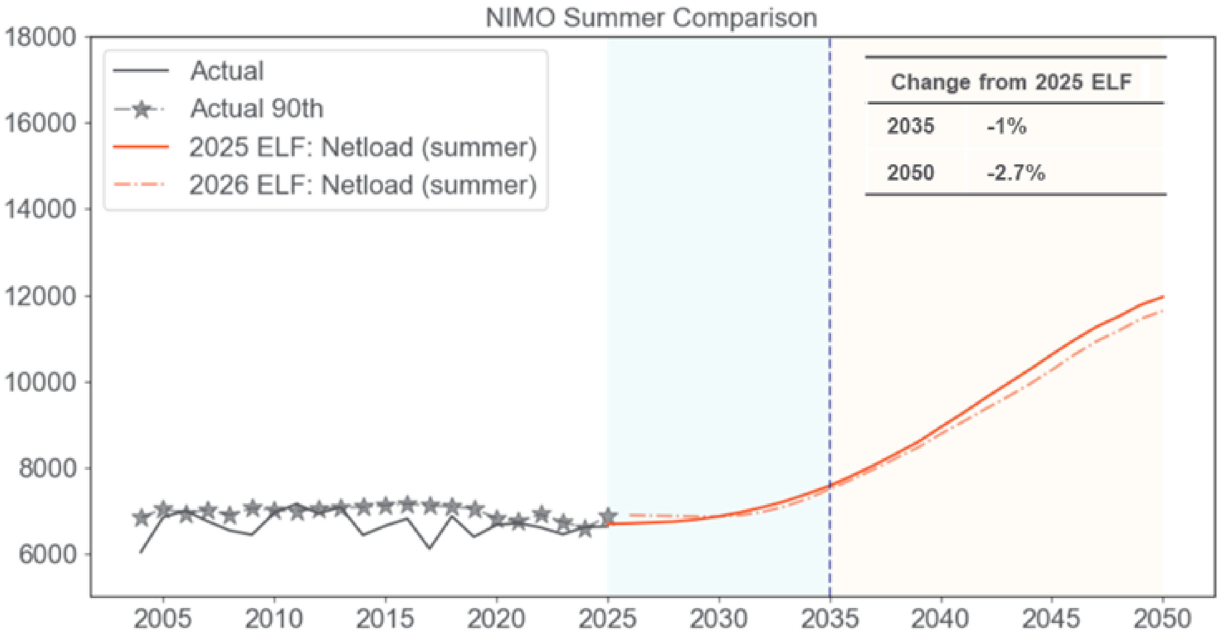

Figure 42: Comparison of Netload forecast to Prior Release (Summer, 90th)

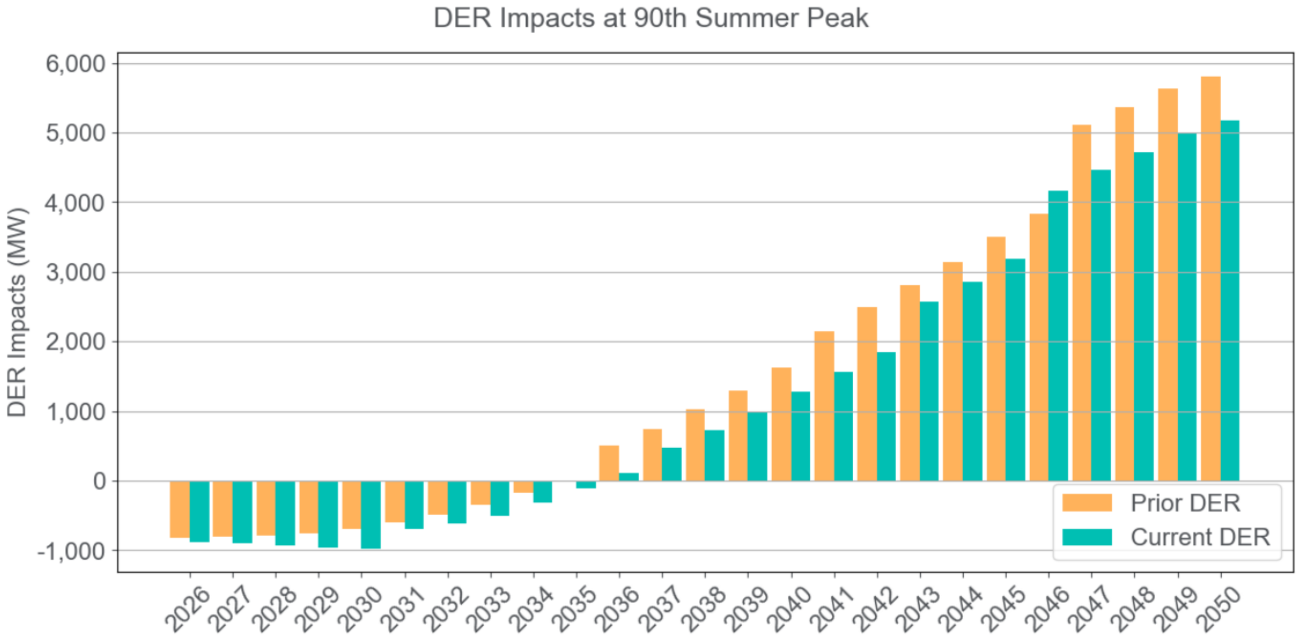

Figure 43: Comparison of DER impacts to Prior Release (Summer, 90th)

Figures 44 and 45 provide a comparison of this year's winter 90th netload and DER impacts at the peak time to the prior forecast release. The 90th winter peak load forecasts are significantly higher by the 10-year forecast horizon. The main driver is a higher EHP penetration projection while modeling under the drafted State Energy plan discussed earlier in the report.

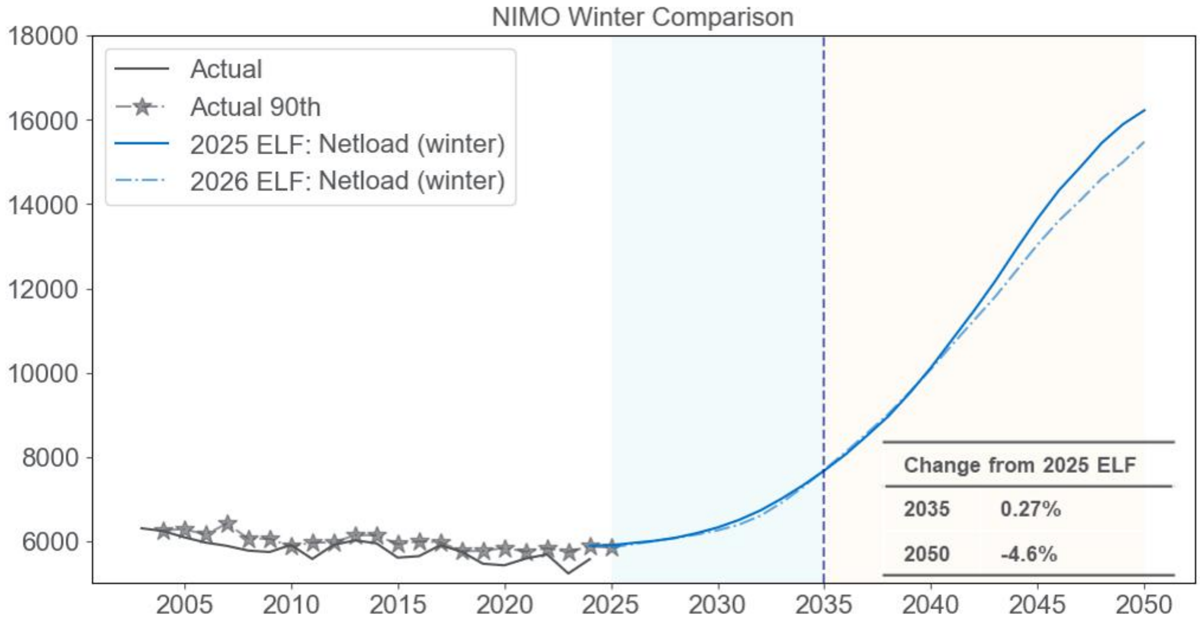

Figure 44: Comparison of Netload forecast to Prior Release (Winter, 90th)

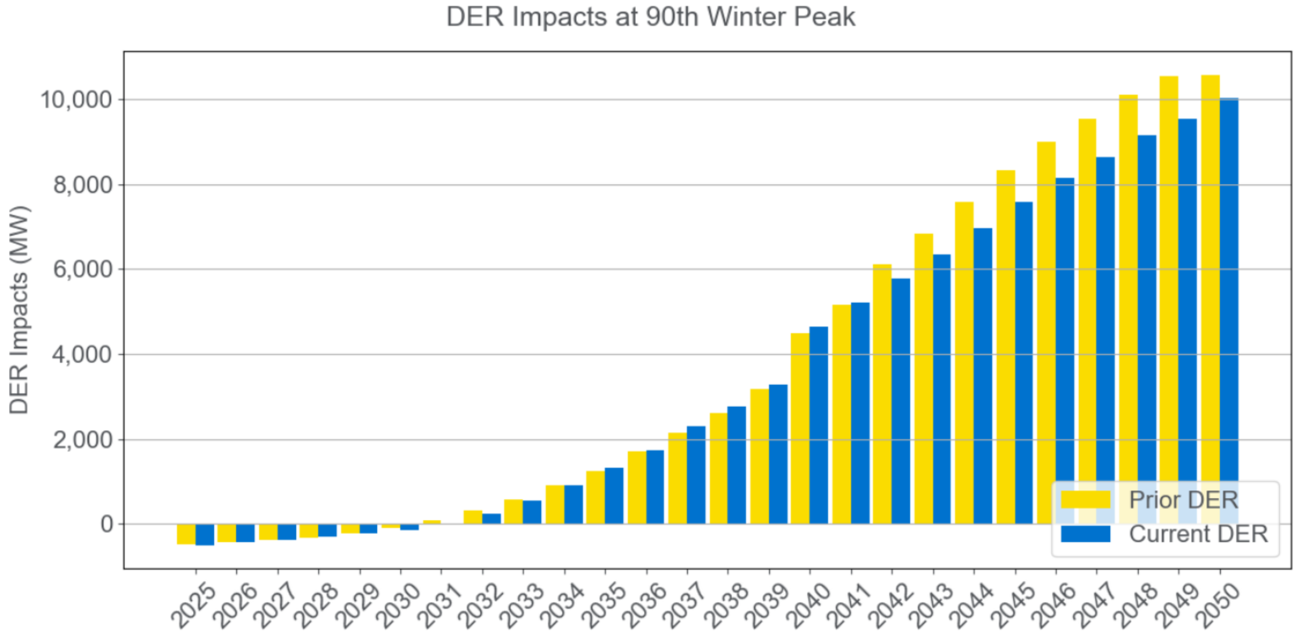

Figure 45: Comparison of DER impacts to Prior Release (Winter, 90th)

7. Uncertainty

7.1. Baseload Quantiles

The forecasts are provided for three Baseload quantiles, namely, 50th, 90th, and 95th. The method to derive the Baseload quantiles is discussed in the previous Forecasting Methodology section. These three specific quantiles are developed to meet the needs of different use cases for system planning and operation. Figure 46 shows the seasonal load forecasts under these three Baseload quantiles and Base DER cases.

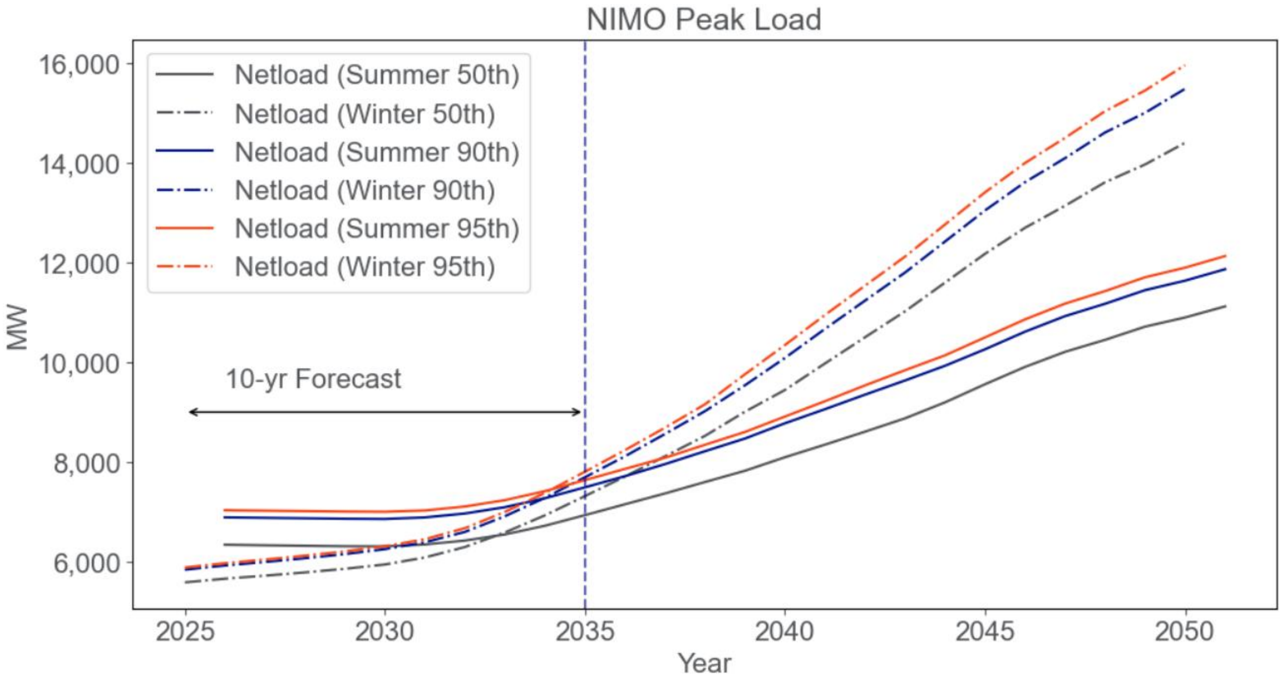

Figure 46: NIMO Seasonal Peak Load Forecasts (50th, 90th and 95th)

7.2. DER Scenarios

The body of this report thus far has shown results for the peak forecast with the base case DERs scenario. The Company has also looked at a number of scenarios where each of the DERs (EE, PV, EV, DR, ES, EH) also has a higher-case and a lower-case scenario, as appropriate. Looking at a range of scenarios can provide planners with additional information on what loads might be under various combinations of DER scenarios[71]. Table 1 summarizes the Base and alternative cases.

Table 1: Base and Alternative DER Cases

Technology	Base Case	High Case	Low Case

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[71] In this forecast, six DERs, each with three cases – base, higher and lower, creates 729 cases (3^6) for each weather scenario. With three weather scenarios 2,187 scenarios are generated for the Company and the same for each individual zone.

Energy Efficiency	NENY until 2025; EE/BE till 2030; SEP afterwards. Some adjustments based on analysis related to organic EE savings; No behavioral saving beyond 2025; Persistent saving saturates.	Reflects sensitivity around base case by assuming higher achievement and lower saturation rate, growth in incremental savings under no funding reduction scenario.	Lower incremental and earlier saturation savings; reflects uncertainty in funding/budgets, policy and behavioral uncertainty.
Solar PV Nameplate (distribution-level)	As per historical trends and estimated queue realization in short term and tied to Additional Action Scenario in NY Draft State Energy Plan in long term.	Assumes faster connection of PV projects and is tied to the Additional Action (Constrained Build) scenario outlined in NY’s Draft Energy Plan.	Assumes slower connection of PV projects in short term and is tied to a ten-year delay in the capacity projections outlined in Additional Action scenario.
Electric Vehicles (on-road)	**ZEV Sales Share:** NY SEP Additional Action; School bus mandate w/ some delay **Technology splits:** BNEF **Stock Growth:** Moodys Baseline, BNEF **Other**: Average Tariff & Tax Credit Repeal Impacts **Profiles:** Empirical profiles, no managed charging	**ZEV Sales Share:** NY SEP Net Zero; School bus mandate **Technology splits:** BNEF **Stock Growth:** Moodys High, BNEF **Other**: None **Profiles:** Same as base case	**ZEV Sales Share:** NY SEP Current Policy; School bus mandate w/ longer delay **Technology splits:** BNEF **Stock Growth:** Moodys Low, BNEF **Other**: High Tariff & Tax Credits Repeal Impacts **Profiles:** Substantial’ managed charging for LDEVs & MHDEVs
Electric Heat Pumps Installations	NENY target for 2025; EE/BE till 2030; SEP Additional Action Scenario afterwards. Reflects the impact of All-Electric Building Act and Tariff.	Tied to SEP Net Zero Scenario; Higher Full Electrification – no partial heat pumps in 2050. Assumes no impacts from Tariff but higher impact from All-Electric Building Act. **Profiles**: Based on simulated heating load profiles from NREL. High COP assumptions for each type of heat-pump inferred from external studies, assumes progress in HP technology will improve performance	SEP Current Policy Scenario; Moderate Lower Electrification pace; assumes co-existence of full and partial heat-pumps. Reflects the impact from Tariffs but assumes no impact from All-Electric Building Act. **Profiles**: Based on simulated heating load profiles from NREL. Low COP assumptions for each type of heat-pump inferred from external studies, assumes slightly lower HP performance under colder temperatures.

Demand Response (company program)	SME projections throughout forecast and demand assessment horizons	High case captures upside sensitivity in incremental increase each year	No additional growth (i.e., held flat) to reflect downside uncertainty
Energy Storage Nameplate (distribution-level)	As per historical trends and estimated queue realization in in short term; aligned with NY State ES targets and the Additional Action Scenario in long term.	Assumes storage deployments are faster and are tied to Net Zero A scenario.	Assumes a lower percentage of total projected capacity in the Additional Action scenario impacts the distribution system, and most future capacity is from larger batteries connected to transmission system

Figure 47 presents the uncertainty range of summer peak load under various DER scenarios with gray line highlighting the summer peak load under the Base DER scenario. In the long-term, EV charging load is the primary driver of summer peak load. The Company investigates a managed charging scenario (see detailed discussions on this scenario in the DER Scenarios Appendix C of this report), under which the summer peak load as highlighted by the purple line in the plot may be reduced by about 3.5% by 2035 and 7.4% by the year 2050.

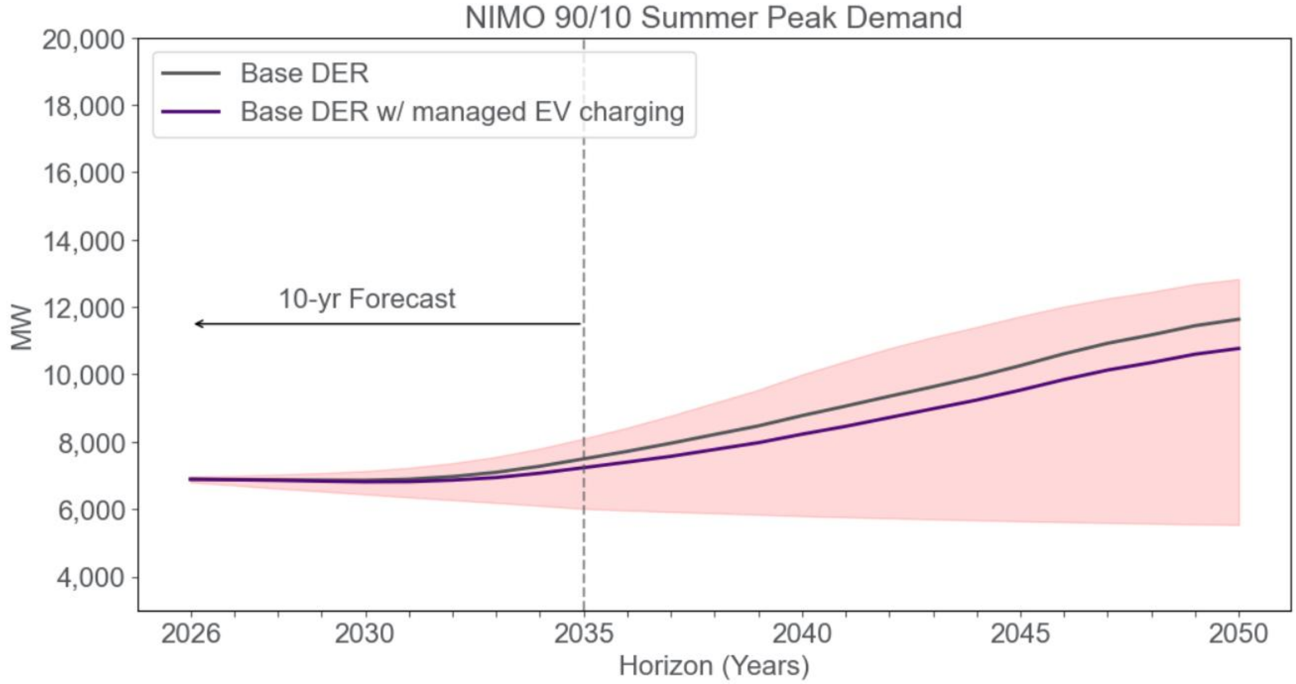

Figure 47: 90th Summer Peak Load Uncertainty Range under DER scenarios

Figure 48 presents the uncertainty range of winter peak load under various DER scenarios with gray line highlighting the winter peak load under the Base DER scenario. In the long-term, electric heating load and EV charging load are the primary drivers of winter peak load growth. Under the Base DER scenario, the peak load grows more than double the Company's peak load as of now. With the same EH penetration but technology advancing on heat pump performance, it is possible to expect a more moderate load growth. The Company analyzes a high performance EHP case and presents the load using the dashed black line in the plot. The Company also analyzes a more accelerated and a more moderated EHP adoption case presenting as the solid green line and the solid red line, respectively. The winter peak load under an EV managed charging case is presented using the purple line in the plot.

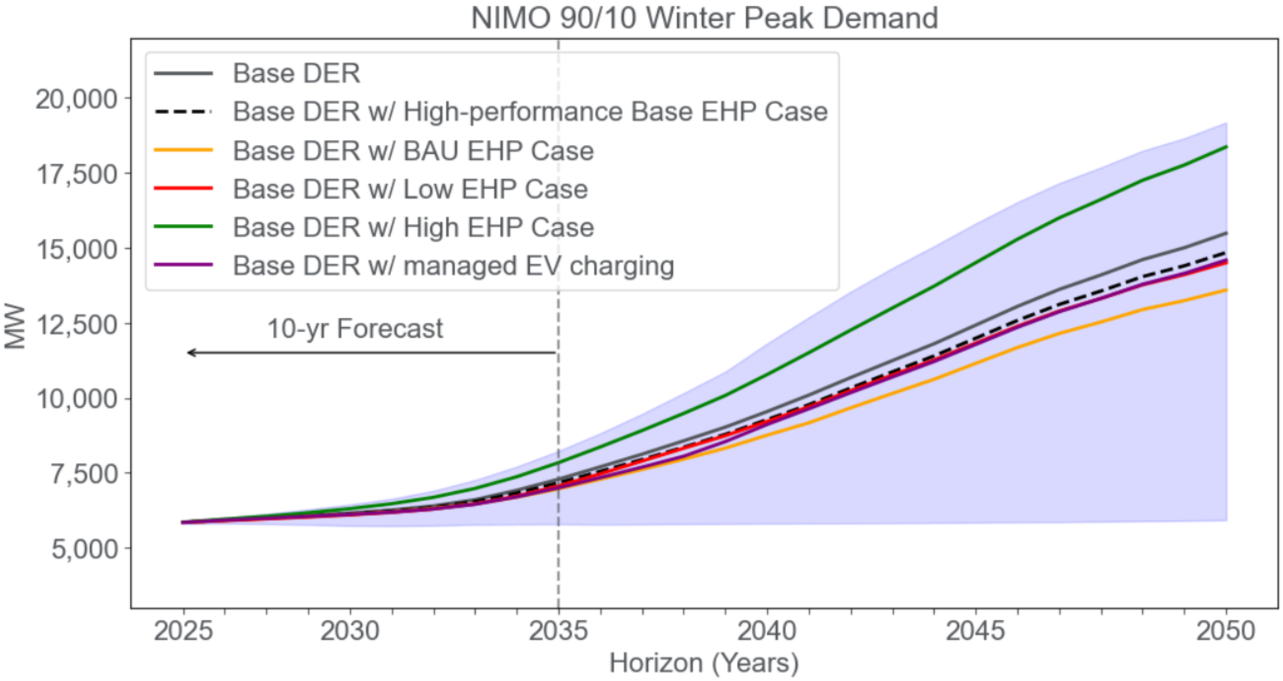

Figure 48: 90th Winter Peak Load Uncertainty Range under DER scenarios

Appendix A: Forecast Details

NIMO (COMPANY)

Summer Peak Load

Year	Actual	50th	90th	95th
2004	6,032	6,556	6,831	6,909
2005	6,838	6,772	7,039	7,114
2006	6,996	6,666	6,935	7,011
2007	6,751	6,718	7,015	7,099
2008	6,536	6,618	6,895	6,974
2009	6,437	6,631	7,053	7,179
2010	6,943	6,698	7,002	7,089
2011	7,149	6,678	6,983	7,069
2012	6,931	6,712	7,038	7,131
2013	7,077	6,755	7,069	7,158
2014	6,430	6,772	7,076	7,163
2015	6,644	6,817	7,119	7,205
2016	6,809	6,844	7,153	7,241
2017	6,106	6,807	7,109	7,194
2018	6,865	6,783	7,091	7,178
2019	6,388	6,717	7,044	7,136
2020	6,664	6,498	6,821	6,912
2021	6,706	6,479	6,741	6,815
2022	6,605	6,613	6,913	6,998
2023	6,448	6,446	6,734	6,815
2024	6,616	6,286	6,595	6,682
2025	6,629	6,357	6,857	6,983
2026		6,342	6,890	7,033
2027		6,330	6,880	7,023
2028		6,319	6,871	7,015
2029		6,310	6,862	7,006
2030		6,307	6,857	7,002
2031		6,347	6,889	7,028
2032		6,424	6,967	7,107
2033		6,547	7,094	7,235
2034		6,721	7,273	7,415
2035		6,934	7,492	7,636
2036		7,152	7,715	7,861
2037		7,369	7,957	8,084
2038		7,598	8,215	8,345
2039		7,824	8,470	8,602
2040		8,095	8,776	8,911
2041		8,348	9,059	9,218
2042		8,607	9,350	9,536
2043		8,875	9,634	9,840
2044		9,195	9,929	10,138
2045		9,559	10,260	10,498
2046		9,906	10,612	10,859
2047		10,208	10,924	11,175
2048		10,448	11,172	11,426
2049		10,714	11,445	11,703
2050		10,897	11,635	11,896

Winter Peak Load

Year	Actual	50th	90th	95th
2004	6,238	6,035	6,255	6,317
2005	6,088	6,036	6,283	6,353
2006	5,963	5,870	6,151	6,230
2007	5,884	6,153	6,417	6,491
2008	5,773	5,806	6,056	6,127
2009	5,739	5,815	6,055	6,123
2010	5,908	5,623	5,870	5,940
2011	5,574	5,702	5,967	6,042
2012	5,911	5,664	5,962	6,047
2013	6,014	5,856	6,141	6,221
2014	5,948	5,876	6,138	6,212
2015	5,606	5,713	5,925	5,985
2016	5,641	5,712	5,992	6,071
2017	5,901	5,695	5,970	6,048
2018	5,747	5,493	5,762	5,838
2019	5,460	5,492	5,762	5,839
2020	5,423	5,570	5,838	5,913
2021	5,582	5,508	5,750	5,818
2022	5,683	5,548	5,831	5,911
2023	5,229	5,491	5,741	5,812
2024	5,568	5,681	5,874	5,928
2025		5,586	5,841	5,884
2026		5,660	5,924	5,971
2027		5,720	5,995	6,043
2028		5,786	6,070	6,121
2029		5,858	6,153	6,207
2030		5,945	6,253	6,310
2031		6,085	6,390	6,451
2032		6,295	6,598	6,673
2033		6,587	6,912	6,999
2034		6,930	7,281	7,379
2035		7,316	7,693	7,804
2036		7,708	8,114	8,238
2037		8,113	8,561	8,686
2038		8,523	9,019	9,156
2039		9,008	9,538	9,759
2040		9,444	10,086	10,345
2041		9,976	10,668	10,947
2042		10,500	11,235	11,534
2043		11,020	11,798	12,117
2044		11,597	12,420	12,761
2045		12,174	13,044	13,407
2046		12,696	13,610	13,995
2047		13,136	14,092	14,498
2048		13,608	14,606	15,034
2049		13,965	15,001	15,449
2050		14,399	15,482	15,956

Summer Peak Load (MW, 50th)

Year	Baseload	EE	PV	ES	DR	EV	EHP	Final Load	Peak Hour
2026	7,197	(672)	(222)	(5)	5	34	4	6,342	20
2027	7,215	(706)	(248)	(15)	6	68	9	6,330	20
2028	7,234	(750)	(268)	(26)	7	108	14	6,319	20
2029	7,246	(797)	(284)	(38)	8	156	19	6,310	20
2030	6,956	(844)	-	(51)	3	220	23	6,307	21
2031	6,967	(892)	-	(62)	4	299	31	6,347	21
2032	6,976	(939)	-	(72)	4	407	47	6,424	21
2033	6,983	(984)	-	(82)	5	552	74	6,547	21
2034	6,987	(1,030)	-	(93)	5	746	106	6,721	21
2035	6,990	(1,076)	-	(104)	6	977	140	6,934	21
2036	6,994	(1,120)	-	(115)	6	1,224	162	7,152	21
2037	6,998	(1,165)	-	(125)	7	1,475	179	7,369	21
2038	7,002	(1,210)	-	(135)	7	1,738	196	7,598	21
2039	7,006	(1,253)	-	(145)	8	1,995	214	7,824	21
2040	7,009	(1,298)	-	(155)	8	2,299	232	8,095	21
2041	7,012	(1,329)	-	(164)	9	2,571	250	8,348	21
2042	7,014	(1,361)	-	(174)	9	2,850	269	8,607	21
2043	6,754	(1,305)	-	(184)	4	3,346	260	8,875	22
2044	5,841	(891)	-	-	4	4,024	218	9,195	24
2045	5,843	(909)	-	-	4	4,388	232	9,559	24
2046	5,845	(926)	-	-	4	4,736	246	9,906	24
2047	5,847	(941)	-	-	4	5,040	259	10,208	24
2048	5,848	(956)	-	-	5	5,279	272	10,448	24
2049	5,849	(971)	-	-	5	5,546	285	10,714	24
2050	5,851	(984)	-	-	5	5,728	297	10,897	24

Summer Peak Load (MW, 90th)

Year	Baseload	EE	PV	ES	DR	EV	EHP	Final Load	Peak Hour
2026	7,768	(731)	(187)	(5)	5	34	5	6,890	20
2027	7,786	(768)	(209)	(15)	6	70	10	6,880	20
2028	7,805	(815)	(226)	(26)	7	110	16	6,871	20
2029	7,818	(867)	(239)	(38)	8	159	21	6,862	20
2030	7,829	(923)	(249)	(51)	9	215	27	6,857	20
2031	7,575	(969)	-	(62)	4	305	35	6,889	21
2032	7,584	(1,020)	-	(72)	4	416	54	6,967	21
2033	7,591	(1,070)	-	(82)	5	564	86	7,094	21
2034	7,595	(1,120)	-	(93)	5	762	123	7,273	21
2035	7,599	(1,169)	-	(104)	6	999	162	7,492	21
2036	7,602	(1,218)	-	(115)	6	1,251	188	7,715	21
2037	7,481	(1,195)	-	(125)	3	1,603	190	7,957	22
2038	7,485	(1,238)	-	(135)	3	1,893	208	8,215	22
2039	7,489	(1,280)	-	(145)	3	2,176	227	8,470	22
2040	7,492	(1,323)	-	(155)	4	2,512	246	8,776	22
2041	7,495	(1,355)	-	(164)	4	2,814	266	9,059	22
2042	7,497	(1,387)	-	(174)	4	3,124	286	9,350	22
2043	7,067	(1,191)	-	-	4	3,470	284	9,634	23
2044	7,069	(1,216)	-	-	4	3,768	303	9,929	23
2045	7,071	(1,240)	-	-	4	4,101	323	10,260	23
2046	6,456	(1,006)	-	-	4	4,840	318	10,612	24
2047	6,457	(1,023)	-	-	4	5,150	336	10,924	24
2048	6,459	(1,039)	-	-	5	5,395	352	11,172	24
2049	6,460	(1,055)	-	-	5	5,667	369	11,445	24
2050	6,462	(1,069)	-	-	5	5,854	384	11,635	24

Winter Peak Load (MW, 50th)

Year	Baseload	EE	PV	ES	DR	EV	EHP	Final Load	Peak Hour
2025	6,091	(528)	-	(1)	-	20	4	5,586	19
2026	6,101	(513)	-	(8)	-	57	22	5,660	19
2027	6,116	(518)	-	(19)	-	102	39	5,720	19
2028	6,130	(524)	-	(31)	-	155	55	5,786	19
2029	6,140	(530)	-	(43)	-	221	71	5,858	19
2030	6,112	(564)	-	(56)	-	330	122	5,945	20
2031	6,121	(572)	-	(66)	-	447	156	6,085	20
2032	6,127	(580)	-	(75)	-	604	219	6,295	20
2033	6,132	(589)	-	(86)	-	817	313	6,587	20
2034	6,135	(598)	-	(97)	-	1,086	406	6,930	20
2035	6,138	(608)	-	(108)	-	1,389	505	7,316	20
2036	6,141	(616)	-	(119)	-	1,698	605	7,708	20
2037	6,144	(626)	-	(129)	-	2,022	702	8,113	20
2038	6,021	(674)	-	(139)	-	2,538	777	8,523	21
2039	6,024	(685)	-	(149)	-	2,950	867	9,008	21
2040	6,027	(701)	-	(159)	-	3,323	955	9,444	21
2041	5,224	(536)	-	-	-	4,260	1,028	9,976	24
2042	5,227	(549)	-	-	-	4,708	1,115	10,500	24
2043	5,229	(561)	-	-	-	5,147	1,205	11,020	24
2044	5,230	(573)	-	-	-	5,642	1,297	11,597	24
2045	5,232	(584)	-	-	-	6,134	1,392	12,174	24
2046	5,234	(594)	-	-	-	6,566	1,491	12,696	24
2047	5,235	(604)	-	-	-	6,914	1,592	13,136	24
2048	5,236	(614)	-	-	-	7,294	1,692	13,608	24
2049	5,237	(622)	-	-	-	7,558	1,792	13,965	24
2050	5,238	(631)	-	-	-	7,875	1,916	14,399	24

Winter Peak Load (MW, 90th)

Year	Baseload	EE	PV	ES	DR	EV	EHP	Final Load	Peak Hour
2025	6,342	(528)	-	(1)	-	20	6	5,841	19
2026	6,353	(513)	-	(8)	-	60	33	5,924	19
2027	6,368	(518)	-	(19)	-	107	57	5,995	19
2028	6,382	(524)	-	(31)	-	162	81	6,070	19
2029	6,391	(530)	-	(43)	-	231	104	6,153	19
2030	6,401	(539)	-	(56)	-	312	135	6,253	19
2031	6,410	(548)	-	(66)	-	423	172	6,390	19
2032	6,373	(580)	-	(75)	-	633	247	6,598	20
2033	6,378	(589)	-	(86)	-	856	354	6,912	20
2034	6,380	(598)	-	(97)	-	1,137	459	7,281	20
2035	6,383	(608)	-	(108)	-	1,454	572	7,693	20
2036	6,387	(616)	-	(119)	-	1,778	685	8,114	20
2037	6,259	(665)	-	(129)	-	2,292	805	8,561	21
2038	6,262	(674)	-	(139)	-	2,656	914	9,019	21
2039	6,265	(685)	-	(149)	-	3,086	1,020	9,538	21
2040	5,453	(523)	-	-	-	3,966	1,190	10,086	24
2041	5,456	(536)	-	-	-	4,452	1,297	10,668	24
2042	5,458	(549)	-	-	-	4,920	1,406	11,235	24
2043	5,460	(561)	-	-	-	5,379	1,520	11,798	24
2044	5,462	(573)	-	-	-	5,895	1,636	12,420	24
2045	5,463	(584)	-	-	-	6,409	1,755	13,044	24
2046	5,465	(594)	-	-	-	6,860	1,880	13,610	24
2047	5,466	(604)	-	-	-	7,223	2,007	14,092	24
2048	5,467	(614)	-	-	-	7,620	2,133	14,606	24
2049	5,468	(622)	-	-	-	7,896	2,259	15,001	24
2050	5,470	(631)	-	-	-	8,227	2,416	15,482	24

Zone A (Western Region)

Summer Peak Load (MW, 50th)

Year	Baseload	EE	PV	ES	DR	EV	EHP	Final Load
2026	2,183	(250)	(36)	-	2	8	0	1,908
2027	2,187	(264)	(41)	-	3	17	1	1,902
2028	2,191	(280)	(45)	(1)	3	27	1	1,897
2029	2,194	(299)	(50)	(2)	4	39	3	1,889
2030	2,198	(319)	(55)	(4)	4	53	4	1,881
2031	2,201	(339)	(60)	(7)	5	71	6	1,877
2032	2,203	(360)	(63)	(9)	5	96	10	1,882
2033	2,133	(369)	(1)	(10)	2	137	16	1,908
2034	2,133	(387)	(1)	(11)	2	185	24	1,945
2035	2,103	(386)	-	(12)	1	257	29	1,993
2036	2,103	(401)	-	(14)	1	323	33	2,046
2037	2,103	(416)	-	(16)	1	390	37	2,100
2038	2,019	(365)	-	-	1	465	35	2,156
2039	2,019	(376)	-	-	1	536	38	2,219
2040	2,019	(389)	-	-	1	622	42	2,294
2041	1,887	(317)	-	-	1	760	38	2,369
2042	1,886	(324)	-	-	2	848	41	2,453
2043	1,885	(332)	-	-	2	933	45	2,533
2044	1,884	(338)	-	-	2	1,016	48	2,612
2045	1,883	(345)	-	-	2	1,110	52	2,701
2046	1,881	(352)	-	-	2	1,199	55	2,786
2047	1,879	(358)	-	-	2	1,277	59	2,859
2048	1,878	(363)	-	-	2	1,338	62	2,917
2049	1,876	(370)	-	-	2	1,407	65	2,980
2050	1,874	(373)	-	-	2	1,454	68	3,025

Summer Peak Load (MW, 90th)

Year	Baseload	EE	PV	ES	DR	EV	EHP	Final Load
2026	2,299	(250)	(37)	-	2	9	0	2,023
2027	2,302	(264)	(42)	-	3	18	1	2,017
2028	2,306	(280)	(47)	(1)	3	28	2	2,012
2029	2,310	(299)	(52)	(2)	4	40	3	2,004
2030	2,313	(319)	(57)	(4)	4	54	4	1,996
2031	2,317	(339)	(62)	(7)	5	73	7	1,994
2032	2,319	(360)	(65)	(9)	5	99	11	2,000
2033	2,319	(377)	(67)	(10)	5	134	19	2,022
2034	2,212	(370)	-	(11)	1	203	24	2,060
2035	2,211	(386)	-	(12)	1	267	32	2,114
2036	2,211	(401)	-	(14)	1	335	38	2,170
2037	2,211	(416)	-	(16)	1	405	42	2,227
2038	2,129	(365)	-	-	1	482	42	2,290
2039	2,129	(376)	-	-	1	556	46	2,357
2040	2,128	(389)	-	-	1	645	51	2,436
2041	2,128	(399)	-	-	2	724	55	2,509
2042	2,127	(408)	-	-	2	807	60	2,587
2043	1,970	(332)	-	-	2	968	59	2,667
2044	1,969	(338)	-	-	2	1,054	64	2,750
2045	1,967	(345)	-	-	2	1,151	69	2,844
2046	1,966	(352)	-	-	2	1,243	73	2,933
2047	1,964	(358)	-	-	2	1,324	78	3,010
2048	1,962	(363)	-	-	2	1,388	82	3,072
2049	1,961	(370)	-	-	2	1,459	86	3,138
2050	1,959	(373)	-	-	2	1,507	90	3,186

Winter Peak Load (MW, 50th)

Year	Baseload	EE	PV	ES	DR	EV	EHP	Final Load
2025	1,865	(174)	-	-	-	6	1	1,698
2026	1,864	(170)	-	-	-	17	2	1,713
2027	1,865	(172)	-	(0)	-	29	4	1,726
2028	1,865	(174)	-	(1)	-	44	7	1,740
2029	1,863	(176)	-	(3)	-	62	11	1,757
2030	1,862	(179)	-	(5)	-	83	16	1,777
2031	1,860	(182)	-	(8)	-	112	21	1,803
2032	1,858	(184)	-	(10)	-	151	30	1,844
2033	1,849	(195)	-	(11)	-	219	44	1,906
2034	1,845	(198)	-	(11)	-	289	58	1,982
2035	1,841	(201)	-	(12)	-	367	72	2,066
2036	1,782	(229)	-	(15)	-	529	91	2,158
2037	1,778	(232)	-	(17)	-	629	106	2,265
2038	1,775	(235)	-	(19)	-	728	120	2,370
2039	1,700	(217)	-	-	-	872	142	2,497
2040	1,696	(222)	-	-	-	982	157	2,613
2041	1,603	(177)	-	-	-	1,126	183	2,735
2042	1,599	(181)	-	-	-	1,242	202	2,862
2043	1,595	(185)	-	-	-	1,357	221	2,987
2044	1,591	(189)	-	-	-	1,485	240	3,127
2045	1,586	(192)	-	-	-	1,612	260	3,266
2046	1,582	(196)	-	-	-	1,724	280	3,390
2047	1,578	(199)	-	-	-	1,813	301	3,493
2048	1,573	(202)	-	-	-	1,911	322	3,604
2049	1,569	(205)	-	-	-	1,979	343	3,686
2050	1,564	(208)	-	-	-	2,060	369	3,786

Winter Peak Load (MW, 90th)

Year	Baseload	EE	PV	ES	DR	EV	EHP	Final Load
2025	1,895	(174)	-	-	-	6	1	1,728
2026	1,894	(170)	-	-	-	17	3	1,744
2027	1,894	(172)	-	(0)	-	30	5	1,758
2028	1,894	(174)	-	(1)	-	45	8	1,773
2029	1,893	(176)	-	(3)	-	64	14	1,792
2030	1,892	(179)	-	(5)	-	86	20	1,814
2031	1,890	(182)	-	(8)	-	116	27	1,843
2032	1,887	(184)	-	(10)	-	155	39	1,887
2033	1,880	(195)	-	(11)	-	226	55	1,954
2034	1,876	(198)	-	(11)	-	298	72	2,036
2035	1,872	(201)	-	(12)	-	378	89	2,125
2036	1,808	(229)	-	(15)	-	544	111	2,220
2037	1,804	(232)	-	(17)	-	648	129	2,333
2038	1,801	(235)	-	(19)	-	750	147	2,443
2039	1,797	(238)	-	(20)	-	870	164	2,572
2040	1,720	(222)	-	-	-	1,011	178	2,687
2041	1,716	(228)	-	-	-	1,129	195	2,812
2042	1,712	(233)	-	-	-	1,241	215	2,935
2043	1,619	(185)	-	-	-	1,396	234	3,063
2044	1,615	(189)	-	-	-	1,528	254	3,208
2045	1,610	(192)	-	-	-	1,658	275	3,351
2046	1,606	(196)	-	-	-	1,773	297	3,480
2047	1,602	(199)	-	-	-	1,865	319	3,587
2048	1,597	(202)	-	-	-	1,966	341	3,702
2049	1,593	(205)	-	-	-	2,035	363	3,786
2050	1,589	(208)	-	-	-	2,119	390	3,890

Zone B (Genesee Region)

Summer Peak Load (MW, 50th)

Year	Baseload	EE	PV	ES	DR	EV	EHP	Final Load
2026	440	(33)	(14)	-	0	2	0	394
2027	441	(35)	(16)	-	0	3	1	394
2028	442	(38)	(17)	(1)	0	5	1	392
2029	442	(40)	(17)	(3)	0	7	2	390
2030	442	(43)	(17)	(5)	0	10	2	388
2031	443	(46)	(17)	(7)	0	12	2	387
2032	443	(49)	(17)	(9)	0	16	3	388
2033	443	(52)	(17)	(11)	0	21	5	389
2034	444	(55)	(18)	(16)	0	27	7	390
2035	444	(58)	(18)	(19)	0	35	10	393
2036	444	(61)	(19)	(21)	0	43	11	397
2037	444	(64)	(20)	(23)	0	50	12	401
2038	444	(67)	(20)	(24)	0	58	14	405
2039	444	(69)	(20)	(24)	0	65	15	411
2040	444	(72)	(20)	(24)	0	73	16	418
2041	445	(74)	(20)	(24)	0	80	17	424
2042	445	(76)	(20)	(24)	0	88	18	431
2043	385	(61)	-	-	0	98	16	439
2044	385	(62)	-	-	0	105	17	446
2045	386	(63)	-	-	0	113	18	453
2046	386	(65)	-	-	0	120	19	460
2047	386	(66)	-	-	0	126	20	466
2048	386	(67)	-	-	0	131	21	471
2049	386	(68)	-	-	0	136	22	476
2050	386	(69)	-	-	0	140	23	480

Summer Peak Load (MW, 90th)

Year	Baseload	EE	PV	ES	DR	EV	EHP	Final Load
2026	482	(33)	(15)	-	0	2	0	436
2027	483	(35)	(16)	-	0	3	1	436
2028	483	(38)	(18)	(1)	0	5	1	434
2029	484	(40)	(18)	(3)	0	7	2	432
2030	484	(43)	(18)	(5)	0	10	2	430
2031	485	(46)	(18)	(7)	0	13	3	429
2032	485	(49)	(17)	(9)	0	17	4	430
2033	485	(52)	(18)	(11)	0	22	6	432
2034	485	(55)	(18)	(16)	0	28	8	433
2035	486	(58)	(19)	(19)	0	36	11	436
2036	462	(57)	-	(21)	0	46	12	441
2037	462	(60)	-	(23)	0	54	13	446
2038	462	(62)	-	(24)	0	62	14	452
2039	462	(65)	-	(24)	0	70	15	459
2040	462	(67)	-	(24)	0	79	16	466
2041	462	(69)	-	(24)	0	86	18	474
2042	463	(71)	-	(24)	0	95	19	482
2043	463	(72)	-	(24)	0	103	20	489
2044	463	(74)	-	(24)	0	110	21	496
2045	463	(75)	-	(25)	0	118	23	504
2046	463	(77)	-	(25)	0	125	24	511
2047	463	(78)	-	(25)	0	132	25	517
2048	463	(79)	-	(25)	0	137	26	522
2049	463	(80)	-	(25)	0	142	27	528
2050	463	(81)	-	(25)	0	147	28	532

Winter Peak Load (MW, 50th)								
Year	**Baseload**	**EE**	**PV**	**ES**	**DR**	**EV**	**EHP**	**Final Load**
2025	364	(20)	-	-	-	1	0	346
2026	365	(19)	-	-	-	2	2	350
2027	365	(20)	-	(0)	-	4	4	353
2028	365	(20)	-	(2)	-	6	5	354
2029	365	(20)	-	(4)	-	8	6	355
2030	365	(21)	-	(6)	-	11	7	356
2031	365	(21)	-	(8)	-	14	9	359
2032	366	(21)	-	(9)	-	18	13	365
2033	359	(23)	-	(13)	-	29	21	373
2034	359	(23)	-	(18)	-	38	27	383
2035	359	(23)	-	(20)	-	47	33	396
2036	359	(24)	-	(22)	-	56	39	410
2037	360	(24)	-	(23)	-	65	46	423
2038	360	(25)	-	(24)	-	74	52	437
2039	360	(25)	-	(24)	-	84	58	452
2040	360	(26)	-	(24)	-	93	63	466
2041	360	(26)	-	(24)	-	101	69	480
2042	360	(27)	-	(24)	-	111	74	493
2043	360	(28)	-	(24)	-	119	79	506
2044	360	(28)	-	(25)	-	128	84	519
2045	360	(29)	-	(25)	-	137	90	532
2046	360	(29)	-	(25)	-	144	95	545
2047	360	(30)	-	(25)	-	150	101	556
2048	360	(30)	-	(25)	-	156	107	568
2049	360	(31)	-	(25)	-	161	113	578
2050	360	(31)	-	(25)	-	166	120	590

Winter Peak Load (MW, 90th)

Year	Baseload	EE	PV	ES	DR	EV	EHP	Final Load
2025	380	(20)	-	-	-	1	1	361
2026	380	(19)	-	-	-	2	3	366
2027	380	(20)	-	(0)	-	4	5	369
2028	380	(20)	-	(2)	-	6	6	371
2029	380	(20)	-	(4)	-	9	7	373
2030	381	(21)	-	(6)	-	11	9	374
2031	381	(21)	-	(8)	-	15	11	378
2032	381	(21)	-	(9)	-	19	16	385
2033	381	(22)	-	(13)	-	25	22	393
2034	362	(20)	(2)	2	-	26	37	406
2035	362	(20)	(2)	2	-	33	45	420
2036	362	(20)	(2)	2	-	39	54	435
2037	362	(21)	(2)	2	-	46	63	450
2038	362	(21)	(3)	2	-	52	71	464
2039	371	(26)	-	(24)	-	98	61	480
2040	371	(26)	-	(24)	-	109	67	496
2041	371	(27)	-	(24)	-	119	72	511
2042	371	(28)	-	(24)	-	130	77	526
2043	371	(28)	-	(24)	-	140	83	541
2044	371	(29)	-	(25)	-	150	88	556
2045	371	(30)	-	(25)	-	160	94	570
2046	371	(30)	-	(25)	-	168	100	585
2047	371	(31)	-	(25)	-	175	106	597
2048	365	(33)	-	(25)	-	189	114	610
2049	365	(33)	-	(25)	-	195	120	622
2050	365	(34)	-	(25)	-	201	128	635

Zone C (Central Region)

Summer Peak Load (MW, 50th)

Year	Baseload	EE	PV	ES	DR	EV	EHP	Final Load
2026	1,383	(136)	(64)	-	1	5	1	1,189
2027	1,385	(143)	(77)	(2)	1	10	1	1,175
2028	1,388	(152)	(87)	(4)	1	16	2	1,163
2029	1,311	(162)	(9)	(7)	0	23	3	1,159
2030	1,312	(172)	(9)	(12)	0	32	3	1,155
2031	1,314	(182)	(9)	(15)	0	43	5	1,157
2032	1,315	(192)	(9)	(16)	1	59	7	1,165
2033	1,316	(202)	(10)	(17)	1	81	12	1,181
2034	1,317	(211)	(10)	(19)	1	110	17	1,204
2035	1,317	(221)	(10)	(22)	1	144	23	1,232
2036	1,318	(230)	(10)	(25)	1	182	27	1,262
2037	1,318	(240)	(10)	(28)	1	220	30	1,291
2038	1,319	(249)	(10)	(32)	1	260	32	1,321
2039	1,320	(258)	(10)	(35)	1	299	35	1,351
2040	1,320	(268)	(10)	(38)	1	345	38	1,388
2041	1,320	(274)	(10)	(43)	1	386	41	1,423
2042	1,166	(220)	-	-	0	477	37	1,461
2043	1,166	(225)	-	-	0	523	40	1,505
2044	1,166	(230)	-	-	1	568	43	1,548
2045	1,167	(234)	-	-	1	619	45	1,597
2046	1,073	(186)	-	-	1	716	44	1,647
2047	1,073	(190)	-	-	1	763	46	1,693
2048	1,073	(193)	-	-	1	800	48	1,729
2049	1,074	(196)	-	-	1	841	50	1,770
2050	1,074	(198)	-	-	1	869	52	1,798

Summer Peak Load (MW, 90th)

Year	Baseload	EE	PV	ES	DR	EV	EHP	Final Load
2026	1,556	(136)	(61)	-	1	5	1	1,365
2027	1,558	(143)	(74)	(2)	1	10	1	1,352
2028	1,561	(152)	(84)	(4)	1	16	2	1,341
2029	1,563	(162)	(88)	(7)	1	24	3	1,334
2030	1,564	(173)	(91)	(12)	1	32	4	1,327
2031	1,483	(182)	(10)	(15)	0	45	5	1,327
2032	1,484	(192)	(10)	(16)	1	62	8	1,337
2033	1,485	(202)	(10)	(17)	1	84	13	1,353
2034	1,486	(211)	(10)	(19)	1	114	19	1,378
2035	1,486	(221)	(11)	(22)	1	150	26	1,409
2036	1,487	(230)	(11)	(25)	1	188	30	1,441
2037	1,488	(240)	(10)	(28)	1	228	34	1,472
2038	1,488	(249)	(11)	(32)	1	269	37	1,503
2039	1,489	(258)	(11)	(35)	1	310	40	1,535
2040	1,489	(268)	(11)	(38)	1	357	44	1,574
2041	1,490	(274)	(10)	(43)	1	400	47	1,611
2042	1,490	(281)	(10)	(47)	1	444	51	1,648
2043	1,322	(225)	-	-	0	542	48	1,688
2044	1,322	(230)	-	-	1	589	52	1,733
2045	1,322	(234)	-	-	1	641	55	1,784
2046	1,323	(239)	-	-	1	691	58	1,833
2047	1,323	(243)	-	-	1	734	61	1,876
2048	1,218	(193)	-	-	1	829	58	1,913
2049	1,218	(196)	-	-	1	871	60	1,955
2050	1,218	(198)	-	-	1	900	63	1,984

Winter Peak Load (MW, 50th)

Year	Baseload	EE	PV	ES	DR	EV	EHP	Final Load
2025	1,173	(95)	-	-	-	4	1	1,082
2026	1,176	(93)	-	(1)	-	10	4	1,096
2027	1,179	(94)	-	(4)	-	18	6	1,106
2028	1,181	(95)	-	(6)	-	27	8	1,116
2029	1,183	(96)	-	(10)	-	39	11	1,127
2030	1,185	(98)	-	(14)	-	53	14	1,140
2031	1,187	(99)	-	(16)	-	72	19	1,163
2032	1,188	(101)	-	(17)	-	97	28	1,195
2033	1,189	(103)	-	(19)	-	131	40	1,239
2034	1,189	(105)	-	(21)	-	173	53	1,290
2035	1,190	(106)	-	(24)	-	220	66	1,346
2036	1,176	(112)	-	(27)	-	288	81	1,407
2037	1,177	(114)	-	(30)	-	341	94	1,469
2038	1,178	(115)	-	(34)	-	393	107	1,529
2039	1,035	(119)	-	-	-	555	127	1,598
2040	1,036	(122)	-	-	-	625	139	1,678
2041	1,036	(125)	-	-	-	696	152	1,759
2042	1,037	(128)	-	-	-	764	164	1,837
2043	979	(101)	-	-	-	851	185	1,914
2044	980	(103)	-	-	-	930	198	2,005
2045	980	(105)	-	-	-	1,008	212	2,095
2046	980	(107)	-	-	-	1,076	227	2,176
2047	981	(109)	-	-	-	1,131	242	2,244
2048	981	(111)	-	-	-	1,191	256	2,317
2049	981	(112)	-	-	-	1,232	271	2,372
2050	981	(114)	-	-	-	1,282	289	2,439

Winter Peak Load (MW, 90th)

Year	Baseload	EE	PV	ES	DR	EV	EHP	Final Load
2025	1,242	(95)	-	-	-	4	1	1,152
2026	1,245	(93)	-	(1)	-	11	6	1,168
2027	1,248	(94)	-	(4)	-	19	10	1,180
2028	1,250	(95)	-	(6)	-	29	14	1,192
2029	1,252	(96)	-	(10)	-	41	18	1,205
2030	1,254	(98)	-	(14)	-	56	24	1,222
2031	1,256	(99)	-	(16)	-	76	32	1,249
2032	1,257	(101)	-	(17)	-	102	47	1,289
2033	1,258	(103)	-	(19)	-	138	68	1,343
2034	1,247	(109)	-	(21)	-	197	91	1,406
2035	1,248	(110)	-	(24)	-	250	114	1,478
2036	1,249	(112)	-	(27)	-	305	137	1,552
2037	1,249	(114)	-	(30)	-	361	159	1,626
2038	1,250	(115)	-	(34)	-	416	181	1,698
2039	1,106	(119)	-	-	-	587	209	1,783
2040	1,107	(122)	-	-	-	660	230	1,875
2041	1,107	(125)	-	-	-	736	250	1,968
2042	1,108	(128)	-	-	-	807	270	2,057
2043	1,050	(101)	-	-	-	898	301	2,148
2044	1,051	(103)	-	-	-	981	323	2,251
2045	1,051	(105)	-	-	-	1,063	345	2,354
2046	1,051	(107)	-	-	-	1,135	369	2,448
2047	1,051	(109)	-	-	-	1,193	393	2,529
2048	1,052	(111)	-	-	-	1,256	417	2,614
2049	1,052	(112)	-	-	-	1,300	441	2,681
2050	1,052	(114)	-	-	-	1,353	470	2,761

Zone D (North Region)

Summer Peak Load (MW, 50th)

Year	Baseload	EE	PV	ES	DR	EV	EHP	Final Load
2026	101	(14)	-	-	-	0	0	87
2027	101	(15)	-	-	-	1	0	87
2028	101	(16)	-	-	-	1	0	86
2029	102	(17)	-	-	-	1	0	86
2030	102	(18)	-	-	-	2	0	86
2031	102	(19)	-	-	-	3	0	86
2032	102	(20)	-	-	-	3	1	86
2033	102	(21)	-	-	-	5	1	86
2034	102	(23)	-	-	-	6	2	87
2035	102	(24)	-	-	-	8	2	89
2036	102	(25)	-	-	-	10	3	90
2037	102	(26)	-	-	-	12	3	91
2038	102	(27)	-	-	-	13	3	92
2039	102	(28)	-	-	-	15	3	93
2040	102	(29)	-	-	-	17	4	94
2041	103	(30)	-	-	-	19	4	96
2042	103	(30)	-	-	-	21	4	97
2043	103	(31)	-	-	-	23	5	99
2044	103	(32)	-	-	-	24	5	100
2045	103	(32)	-	-	-	26	5	102
2046	103	(33)	-	-	-	28	5	103
2047	103	(33)	-	-	-	29	6	104
2048	99	(31)	-	-	-	31	6	105
2049	99	(31)	-	(0)	-	33	6	106
2050	99	(32)	-	(0)	-	34	6	107

Summer Peak Load (MW, 90th)

Year	Baseload	EE	PV	ES	DR	EV	EHP	Final Load
2026	108	(14)	-	-	-	0	0	94
2027	108	(15)	-	-	-	1	0	94
2028	108	(16)	-	-	-	1	0	94
2029	109	(17)	-	-	-	1	0	93
2030	109	(18)	-	-	-	2	0	93
2031	109	(19)	-	-	-	3	0	93
2032	109	(20)	-	-	-	4	1	93
2033	109	(21)	-	-	-	5	1	94
2034	109	(23)	-	-	-	6	2	95
2035	109	(24)	-	-	-	8	2	96
2036	109	(25)	-	-	-	10	3	98
2037	109	(26)	-	-	-	12	3	99
2038	109	(27)	-	-	-	14	3	100
2039	109	(28)	-	-	-	16	4	101
2040	109	(29)	-	-	-	18	4	102
2041	110	(30)	-	-	-	19	4	104
2042	110	(30)	-	-	-	21	5	105
2043	110	(31)	-	-	-	23	5	107
2044	110	(32)	-	-	-	25	5	109
2045	107	(29)	-	-	-	28	5	110
2046	107	(30)	-	-	-	30	5	112
2047	107	(31)	-	-	-	31	6	113
2048	107	(31)	-	-	-	32	6	114
2049	107	(31)	-	(0)	-	34	6	115
2050	107	(32)	-	(0)	-	35	6	116

Winter Peak Load (MW, 50th)

Year	Baseload	EE	PV	ES	DR	EV	EHP	Final Load
2025	147	(7)	-	-	-	0	0	141
2026	148	(7)	-	-	-	0	1	142
2027	148	(7)	-	-	-	0	2	144
2028	149	(7)	-	-	-	1	2	145
2029	149	(7)	-	-	-	1	3	146
2030	150	(7)	-	-	-	1	3	147
2031	150	(7)	-	-	-	2	5	149
2032	150	(7)	-	-	-	2	6	151
2033	150	(8)	-	-	-	3	9	155
2034	150	(8)	-	-	-	4	11	158
2035	150	(8)	-	-	-	5	14	162
2036	151	(8)	-	-	-	7	16	166
2037	151	(8)	-	-	-	8	19	169
2038	151	(8)	-	-	-	9	21	173
2039	151	(8)	-	-	-	10	24	176
2040	151	(9)	-	-	-	11	26	180
2041	151	(9)	-	-	-	12	28	183
2042	150	(12)	-	-	-	29	20	187
2043	150	(13)	-	-	-	32	21	190
2044	150	(13)	-	-	-	34	23	194
2045	150	(13)	-	-	-	37	24	197
2046	150	(14)	-	-	-	39	25	201
2047	150	(14)	-	-	-	41	27	204
2048	150	(14)	-	(0)	-	42	29	207
2049	150	(14)	-	(0)	-	44	30	210
2050	150	(14)	-	(1)	-	45	32	213

Winter Peak Load (MW, 90th)

Year	Baseload	EE	PV	ES	DR	EV	EHP	Final Load
2025	157	(7)	-	-	-	0	0	151
2026	158	(7)	-	-	-	0	1	153
2027	159	(7)	-	-	-	0	2	154
2028	159	(7)	-	-	-	1	3	156
2029	159	(7)	-	-	-	1	3	157
2030	160	(7)	-	-	-	1	4	158
2031	160	(7)	-	-	-	2	6	160
2032	160	(7)	-	-	-	3	8	163
2033	161	(8)	-	-	-	3	11	168
2034	161	(8)	-	-	-	5	14	172
2035	161	(8)	-	-	-	6	18	176
2036	161	(8)	-	-	-	7	21	181
2037	160	(11)	-	-	-	18	18	185
2038	161	(11)	-	-	-	20	20	190
2039	161	(12)	-	-	-	23	23	195
2040	161	(12)	-	-	-	26	25	199
2041	161	(12)	-	-	-	28	27	204
2042	161	(12)	-	-	-	31	29	208
2043	161	(13)	-	-	-	34	31	213
2044	161	(13)	-	-	-	36	33	217
2045	161	(13)	-	-	-	39	35	222
2046	161	(14)	-	-	-	41	37	226
2047	161	(14)	-	-	-	43	40	230
2048	161	(14)	-	(0)	-	45	42	234
2049	161	(14)	-	(0)	-	46	44	237
2050	161	(14)	-	(1)	-	47	47	241

Zone E (Mohawk Valley Region)

Summer Peak Load (MW, 50th)

Year	Baseload	EE	PV	ES	DR	EV	EHP	Final Load
2026	863	(87)	-	(3)	0	4	1	777
2027	869	(91)	-	(7)	0	8	1	780
2028	874	(97)	-	(11)	0	13	2	782
2029	878	(102)	-	(14)	0	20	3	784
2030	881	(109)	-	(16)	0	29	3	789
2031	885	(115)	-	(18)	0	40	4	796
2032	888	(121)	-	(21)	0	56	6	808
2033	890	(127)	-	(24)	1	76	10	825
2034	891	(134)	-	(28)	1	105	14	849
2035	893	(140)	-	(31)	1	139	19	881
2036	894	(145)	-	(33)	1	177	22	914
2037	895	(151)	-	(36)	1	215	24	948
2038	896	(158)	-	(38)	1	257	26	985
2039	796	(128)	-	-	0	332	22	1,022
2040	797	(132)	-	-	0	390	24	1,078
2041	732	(105)	-	-	0	488	21	1,136
2042	733	(108)	-	-	0	551	22	1,199
2043	734	(110)	-	-	0	612	24	1,260
2044	735	(113)	-	-	0	672	26	1,320
2045	736	(115)	-	-	0	740	27	1,388
2046	736	(117)	-	-	0	805	29	1,453
2047	737	(119)	-	-	0	861	30	1,510
2048	738	(121)	-	-	1	906	32	1,555
2049	738	(123)	-	-	1	955	33	1,605
2050	739	(124)	-	-	1	989	35	1,639

Summer Peak Load (MW, 90th)

Year	Baseload	EE	PV	ES	DR	EV	EHP	Final Load
2026	942	(87)	-	(3)	0	4	1	856
2027	947	(91)	-	(7)	0	8	2	859
2028	953	(97)	-	(11)	0	13	2	861
2029	956	(102)	-	(14)	0	20	3	864
2030	960	(109)	-	(16)	0	30	4	869
2031	964	(115)	-	(18)	0	41	5	877
2032	966	(121)	-	(21)	0	58	8	890
2033	969	(127)	-	(24)	1	79	12	908
2034	970	(134)	-	(28)	1	109	17	934
2035	971	(140)	-	(31)	1	144	22	968
2036	972	(145)	-	(33)	1	183	25	1,003
2037	974	(151)	-	(36)	1	223	28	1,038
2038	975	(158)	-	(38)	1	266	30	1,077
2039	976	(163)	-	(40)	1	309	33	1,116
2040	863	(132)	-	-	0	404	30	1,166
2041	864	(135)	-	-	0	457	33	1,220
2042	789	(108)	-	-	0	571	31	1,283
2043	790	(110)	-	-	0	634	33	1,347
2044	790	(113)	-	-	0	697	36	1,411
2045	791	(115)	-	-	0	767	38	1,482
2046	792	(117)	-	-	0	834	40	1,550
2047	793	(119)	-	-	0	893	42	1,609
2048	793	(121)	-	-	1	939	44	1,657
2049	794	(123)	-	-	1	991	46	1,709
2050	795	(124)	-	-	1	1,025	48	1,744

Winter Peak Load (MW, 50th)

Year	Baseload	EE	PV	ES	DR	EV	EHP	Final Load
2025	782	(61)	-	(0)	-	2	1	724
2026	787	(59)	-	(5)	-	7	5	735
2027	794	(60)	-	(9)	-	12	9	746
2028	800	(60)	-	(12)	-	19	12	758
2029	804	(61)	-	(15)	-	29	15	772
2030	809	(62)	-	(17)	-	41	19	790
2031	813	(63)	-	(19)	-	57	23	811
2032	816	(64)	-	(22)	-	78	32	839
2033	812	(68)	-	(26)	-	118	45	882
2034	813	(69)	-	(29)	-	159	58	932
2035	814	(70)	-	(32)	-	206	72	990
2036	798	(75)	-	(34)	-	281	86	1,055
2037	726	(73)	-	-	-	378	98	1,129
2038	684	(58)	-	-	-	479	107	1,212
2039	685	(59)	-	-	-	567	120	1,314
2040	686	(60)	-	-	-	648	132	1,406
2041	687	(62)	-	-	-	734	143	1,503
2042	688	(63)	-	-	-	820	155	1,601
2043	689	(64)	-	-	-	905	167	1,697
2044	690	(66)	-	-	-	1,001	180	1,806
2045	691	(67)	-	-	-	1,097	193	1,914
2046	692	(68)	-	-	-	1,182	206	2,011
2047	692	(69)	-	-	-	1,249	220	2,092
2048	693	(71)	-	-	-	1,323	233	2,179
2049	693	(71)	-	-	-	1,374	247	2,243
2050	694	(73)	-	-	-	1,437	264	2,322

Winter Peak Load (MW, 90th)

Year	Baseload	EE	PV	ES	DR	EV	EHP	Final Load
2025	822	(61)	-	(0)	-	2	1	765
2026	827	(59)	-	(5)	-	7	7	777
2027	834	(60)	-	(9)	-	13	11	789
2028	840	(60)	-	(12)	-	19	16	803
2029	845	(61)	-	(15)	-	30	20	819
2030	849	(62)	-	(17)	-	43	25	838
2031	853	(63)	-	(19)	-	59	30	860
2032	851	(67)	-	(22)	-	90	42	894
2033	853	(68)	-	(26)	-	123	59	942
2034	854	(69)	-	(29)	-	165	76	998
2035	839	(74)	-	(32)	-	236	94	1,062
2036	841	(75)	-	(34)	-	292	112	1,135
2037	724	(57)	-	-	-	422	127	1,216
2038	726	(58)	-	-	-	497	144	1,308
2039	727	(59)	-	-	-	589	160	1,417
2040	728	(60)	-	-	-	673	176	1,517
2041	729	(62)	-	-	-	762	191	1,621
2042	730	(63)	-	-	-	851	207	1,726
2043	731	(64)	-	-	-	939	223	1,830
2044	732	(66)	-	-	-	1,039	240	1,945
2045	733	(67)	-	-	-	1,138	257	2,061
2046	734	(68)	-	-	-	1,226	275	2,166
2047	734	(69)	-	-	-	1,296	293	2,254
2048	735	(71)	-	-	-	1,373	312	2,348
2049	735	(71)	-	-	-	1,425	330	2,419
2050	736	(73)	-	-	-	1,490	353	2,506

Zone F (Eastern Region)

Summer Peak Load (MW, 50th)

Year	Baseload	EE	PV	ES	DR	EV	EHP	Final Load
2026	2,125	(233)	(12)	(2)	0	9	1	1,889
2027	2,128	(245)	(13)	(5)	1	20	3	1,888
2028	2,132	(261)	(14)	(9)	1	32	4	1,884
2029	2,134	(279)	(14)	(12)	1	46	5	1,881
2030	2,136	(298)	(15)	(14)	1	63	7	1,879
2031	2,138	(318)	(15)	(15)	1	86	9	1,885
2032	2,139	(337)	(15)	(17)	1	118	13	1,902
2033	2,140	(356)	(16)	(18)	1	162	20	1,934
2034	2,141	(375)	(16)	(19)	1	220	29	1,982
2035	2,141	(393)	(16)	(20)	2	292	38	2,044
2036	2,142	(411)	(17)	(22)	2	369	45	2,108
2037	2,143	(429)	(17)	(23)	2	449	49	2,173
2038	2,144	(448)	(17)	(24)	2	533	54	2,243
2039	2,040	(416)	-	(27)	1	667	53	2,319
2040	2,040	(431)	-	(30)	1	776	58	2,415
2041	2,041	(441)	-	(33)	1	874	62	2,504
2042	2,041	(452)	-	(36)	1	974	67	2,596
2043	1,893	(380)	-	-	1	1,111	62	2,688
2044	1,733	(304)	-	-	1	1,312	53	2,795
2045	1,733	(310)	-	-	1	1,436	57	2,917
2046	1,733	(316)	-	-	1	1,556	60	3,035
2047	1,734	(321)	-	-	1	1,661	63	3,138
2048	1,734	(326)	-	-	1	1,744	66	3,219
2049	1,734	(331)	-	-	1	1,836	69	3,309
2050	1,734	(336)	-	-	1	1,898	72	3,370

Summer Peak Load (MW, 90th)

Year	Baseload	EE	PV	ES	DR	EV	EHP	Final Load
2026	2,529	(230)	(101)	(2)	1	9	1	2,209
2027	2,532	(244)	(111)	(5)	2	20	3	2,196
2028	2,536	(261)	(119)	(9)	2	32	5	2,185
2029	2,538	(281)	(128)	(12)	2	46	6	2,172
2030	2,540	(302)	(135)	(14)	2	62	8	2,162
2031	2,416	(318)	(16)	(15)	1	88	10	2,166
2032	2,417	(337)	(16)	(17)	1	121	14	2,184
2033	2,419	(356)	(16)	(18)	1	166	22	2,218
2034	2,419	(375)	(17)	(19)	1	227	32	2,269
2035	2,420	(393)	(17)	(20)	2	300	42	2,333
2036	2,421	(411)	(18)	(22)	2	380	49	2,400
2037	2,421	(429)	(18)	(23)	2	462	54	2,468
2038	2,422	(448)	(18)	(24)	2	548	59	2,541
2039	2,423	(465)	(17)	(27)	2	634	64	2,613
2040	2,423	(483)	(17)	(30)	2	736	70	2,701
2041	2,424	(495)	(17)	(33)	2	828	75	2,784
2042	2,285	(452)	-	(36)	1	1,003	73	2,874
2043	2,285	(462)	-	(38)	1	1,100	78	2,965
2044	2,285	(472)	-	(41)	1	1,196	84	3,053
2045	1,925	(310)	-	-	1	1,478	72	3,167
2046	1,925	(316)	-	-	1	1,602	77	3,289
2047	1,926	(321)	-	-	1	1,709	81	3,396
2048	1,926	(326)	-	-	1	1,795	85	3,480
2049	1,926	(331)	-	-	1	1,889	89	3,574
2050	1,926	(336)	-	-	1	1,954	92	3,638

Winter Peak Load (MW, 50th)

Year	Baseload	EE	PV	ES	DR	EV	EHP	Final Load
2025	1,865	(141)	(0)	(0)	-	6	2	1,731
2026	1,872	(147)	-	(3)	-	20	8	1,750
2027	1,877	(148)	-	(7)	-	35	13	1,771
2028	1,883	(150)	-	(11)	-	53	19	1,794
2029	1,887	(152)	-	(13)	-	75	23	1,820
2030	1,890	(154)	-	(15)	-	101	29	1,851
2031	1,894	(157)	-	(16)	-	138	37	1,895
2032	1,897	(159)	-	(17)	-	188	50	1,958
2033	1,899	(162)	-	(18)	-	255	70	2,043
2034	1,900	(165)	-	(19)	-	340	90	2,145
2035	1,901	(168)	-	(21)	-	435	110	2,258
2036	1,865	(176)	-	(23)	-	571	137	2,374
2037	1,826	(190)	-	(24)	-	741	162	2,515
2038	1,754	(203)	-	(25)	-	949	187	2,662
2039	1,755	(206)	-	(29)	-	1,106	209	2,836
2040	1,662	(192)	-	-	-	1,296	232	2,998
2041	1,560	(153)	-	-	-	1,508	254	3,169
2042	1,560	(156)	-	-	-	1,665	274	3,344
2043	1,561	(160)	-	-	-	1,820	296	3,518
2044	1,562	(163)	-	-	-	1,995	318	3,712
2045	1,562	(166)	-	-	-	2,170	341	3,907
2046	1,563	(169)	-	-	-	2,322	364	4,080
2047	1,563	(172)	-	-	-	2,445	388	4,225
2048	1,564	(175)	-	-	-	2,579	412	4,381
2049	1,564	(177)	-	-	-	2,672	436	4,495
2050	1,565	(179)	-	-	-	2,784	466	4,636

Winter Peak Load (MW, 90th)

Year	Baseload	EE	PV	ES	DR	EV	EHP	Final Load
2025	1,993	(151)	-	(0)	-	8	3	1,853
2026	1,994	(147)	-	(3)	-	21	11	1,876
2027	1,999	(148)	-	(7)	-	37	19	1,900
2028	2,005	(150)	-	(11)	-	56	26	1,926
2029	2,009	(152)	-	(13)	-	78	32	1,954
2030	2,012	(154)	-	(15)	-	105	41	1,989
2031	2,015	(157)	-	(16)	-	144	52	2,039
2032	2,018	(159)	-	(17)	-	196	72	2,110
2033	2,020	(162)	-	(18)	-	267	100	2,207
2034	2,021	(165)	-	(19)	-	356	128	2,321
2035	2,022	(168)	-	(21)	-	455	158	2,447
2036	2,024	(170)	-	(23)	-	557	189	2,576
2037	1,933	(190)	-	(24)	-	775	221	2,715
2038	1,846	(203)	-	(25)	-	992	256	2,866
2039	1,752	(187)	-	-	-	1,198	296	3,058
2040	1,654	(149)	-	-	-	1,402	338	3,245
2041	1,654	(153)	-	-	-	1,575	367	3,444
2042	1,655	(156)	-	-	-	1,739	397	3,635
2043	1,656	(160)	-	-	-	1,901	428	3,825
2044	1,657	(163)	-	-	-	2,083	460	4,037
2045	1,657	(166)	-	-	-	2,265	493	4,249
2046	1,658	(169)	-	-	-	2,424	527	4,440
2047	1,658	(172)	-	-	-	2,552	562	4,600
2048	1,659	(175)	-	-	-	2,692	596	4,773
2049	1,659	(177)	-	-	-	2,789	631	4,902
2050	1,660	(179)	-	-	-	2,906	674	5,061

Appendix B: Historical Seasonal Peaks

Summer

year	dt_NIMO	hr_NIMO	NIMO	dt_Zone_A	hr_Zone_A	Zone_A	dt_Zone_B	hr_Zone_B	Zone_B	dt_Zone_C	hr_Zone_C	Zone_C	dt_Zone_D	hr_Zone_D	Zone_D	dt_Zone_E	hr_Zone_E	Zone_E	dt_Zone_F	hr_Zone_F	Zone_F
2003	06/26/2003	16	6,273.67	08/14/2003	14	1,931.57	07/29/2003	12	364.14	06/26/2003	16	1,266.86	08/14/2003	17	185.54	06/26/2003	16	812.11	06/26/2003	16	1,954.49
2004	06/09/2004	16	6,031.71	06/09/2004	15	1,886.84	07/08/2004	9	372.33	06/09/2004	16	1,271.14	09/21/2004	10	133.80	07/22/2004	15	756.08	08/30/2004	15	1,894.11
2005	08/04/2005	15	6,838.21	08/03/2005	15	2,075.61	07/12/2005	15	367.40	08/04/2005	16	1,425.00	08/21/2005	15	159.84	08/04/2005	14	826.21	08/04/2005	17	2,087.99
2006	08/02/2006	13	6,995.75	08/02/2006	13	2,057.31	08/02/2006	13	391.46	08/01/2006	15	1,482.54	08/01/2006	15	119.18	08/02/2006	14	830.15	08/02/2006	14	2,192.95
2007	08/02/2007	16	6,751.42	08/03/2007	14	1,990.72	07/10/2007	18	382.96	08/02/2007	17	1,389.69	06/26/2007	13	115.59	06/27/2007	15	829.23	08/02/2007	17	2,090.12
2008	06/09/2008	17	6,535.60	07/18/2008	15	1,909.82	07/08/2008	17	368.22	06/09/2008	16	1,357.61	06/25/2008	12	94.45	07/08/2008	15	834.68	06/10/2008	17	2,111.10
2009	08/17/2009	16	6,436.96	08/17/2009	14	1,893.26	08/17/2009	15	375.37	08/17/2009	17	1,313.09	08/17/2009	14	87.17	08/17/2009	15	812.41	08/17/2009	17	1,984.33
2010	07/08/2010	16	6,942.76	07/08/2010	16	2,014.82	07/06/2010	14	396.18	07/08/2010	16	1,385.78	07/08/2010	11	93.88	07/08/2010	16	871.49	07/08/2010	15	2,185.36
2011	07/21/2011	17	7,149.26	07/21/2011	15	2,146.20	07/22/2011	16	414.05	07/21/2011	17	1,402.97	07/22/2011	12	90.84	07/21/2011	15	901.86	07/21/2011	17	2,234.62
2012	07/17/2012	16	6,931.25	07/17/2012	15	2,012.23	06/21/2012	16	411.74	07/17/2012	17	1,407.55	08/02/2012	18	100.90	07/17/2012	15	871.57	07/17/2012	17	2,204.95
2013	07/19/2013	14	7,077.49	07/19/2013	14	2,054.14	07/17/2013	15	404.46	07/19/2013	17	1,427.82	07/19/2013	14	93.57	07/19/2013	16	887.13	07/19/2013	17	2,270.33
2014	07/01/2014	16	6,429.50	07/01/2014	14	1,904.45	06/30/2014	15	365.55	07/01/2014	16	1,313.87	09/16/2014	9	115.64	07/23/2014	13	783.82	07/23/2014	15	2,117.30
2015	09/08/2015	15	6,643.58	09/08/2015	15	1,964.34	09/08/2015	15	383.29	09/08/2015	17	1,345.24	08/12/2015	9	102.66	09/08/2015	17	802.91	07/29/2015	18	2,123.12
2016	08/11/2016	17	6,809.21	08/11/2016	14	2,010.11	08/11/2016	16	398.77	08/11/2016	17	1,371.99	08/12/2016	15	103.81	08/11/2016	18	811.46	08/12/2016	15	2,179.48
2017	09/25/2017	17	6,106.13	07/21/2017	15	1,807.53	09/25/2017	16	362.23	09/25/2017	17	1,226.92	09/26/2017	20	84.60	09/25/2017	17	737.42	08/22/2017	17	2,026.34
2018	07/16/2018	17	6,865.03	09/05/2018	17	2,033.66	09/05/2018	18	418.08	07/02/2018	15	1,388.25	07/02/2018	13	99.02	08/06/2018	18	819.44	07/02/2018	18	2,261.89
2019	07/29/2019	18	6,388.46	07/10/2019	17	1,878.13	07/29/2019	15	398.88	07/19/2019	16	1,267.49	07/20/2019	19	89.97	07/29/2019	18	790.61	07/29/2019	19	2,109.97
2020	07/09/2020	18	6,664.44	07/09/2020	18	1,905.52	07/09/2020	18	407.54	07/09/2020	18	1,356.41	07/10/2020	14	92.05	07/09/2020	19	822.31	07/27/2020	18	2,219.84
2021	06/29/2021	18	6,706.50	06/29/2021	17	1,981.66	08/25/2021	18	425.82	08/26/2021	17	1,332.00	08/26/2021	19	91.56	06/29/2021	19	800.23	06/28/2021	18	2,222.98
2022	07/20/2022	18	6,605.21	07/20/2022	17	1,820.11	07/20/2022	19	398.69	07/20/2022	18	1,301.29	08/07/2022	18	92.41	08/08/2022	16	783.20	07/20/2022	19	2,244.85
2023	09/06/2023	19	6,448.30	09/06/2023	18	1,869.36	07/17/2023	23	510.50	09/06/2023	19	1,291.60	07/06/2023	18	92.81	09/06/2023	20	817.70	09/07/2023	18	2,055.41
2024	06/19/2024	20	6,615.92	06/19/2024	20	2,001.07	06/19/2024	21	412.40	06/19/2024	20	1,291.79	06/19/2024	20	93.28	07/15/2024	19	816.24	07/10/2024	18	2,189.36
2025	07/24/2025	20	6,629.04	07/24/2025	20	2,018.64	08/12/2025	21	422.62	06/23/2025	20	1,317.89	06/23/2025	21	95.30	08/12/2025	21	838.56	06/24/2025	20	2,138.31

Winter

year	dt_NIMO	hr_NIMO	NIMO	dt_Zone_A	hr_Zone_A	Zone_A	dt_Zone_B	hr_Zone_B	Zone_B	dt_Zone_C	hr_Zone_C	Zone_C	dt_Zone_D	hr_Zone_D	Zone_D	dt_Zone_E	hr_Zone_E	Zone_E	dt_Zone_F	hr_Zone_F	Zone_F
2002	03/03/2003	20	5,732.02	03/03/2003	20	1,795.04	03/10/2003	19	330.07	03/03/2003	20	1,188.05	03/14/2003	19	140.32	03/03/2003	19	699.97	03/03/2003	19	1,619.28
2003	01/15/2004	19	6,301.68	01/22/2004	19	1,853.06	01/14/2004	18	408.12	01/14/2004	19	1,256.48	01/16/2004	11	294.19	01/15/2004	20	796.69	01/15/2004	19	1,806.97
2004	12/20/2004	19	6,237.65	12/14/2004	19	1,861.73	12/20/2004	19	379.88	12/20/2004	18	1,239.19	12/14/2004	11	174.66	12/20/2004	18	778.53	12/20/2004	19	1,829.43
2005	12/14/2005	18	6,088.25	12/13/2005	19	1,855.69	12/13/2005	18	350.25	12/14/2005	18	1,199.09	11/19/2005	9	175.29	12/14/2005	18	797.24	12/14/2005	18	1,735.12
2006	02/05/2007	19	5,962.90	02/05/2007	20	1,824.32	12/04/2006	19	358.40	02/05/2007	19	1,210.86	01/31/2007	8	159.83	02/05/2007	19	759.41	03/06/2007	19	1,715.03
2007	12/13/2007	18	5,884.08	02/11/2008	19	1,785.32	12/03/2007	18	361.26	12/04/2007	18	1,170.42	01/05/2008	19	193.04	12/13/2007	18	821.55	12/13/2007	18	1,723.98
2008	12/08/2008	18	5,772.66	12/08/2008	18	1,757.91	01/12/2009	19	340.74	12/22/2008	18	1,167.48	01/16/2009	9	135.86	01/28/2009	18	785.09	12/08/2008	18	1,644.05
2009	12/17/2009	18	5,739.37	12/16/2009	18	1,767.01	12/17/2009	19	350.66	12/17/2009	18	1,152.44	12/29/2009	19	135.91	12/22/2009	19	759.45	12/29/2009	18	1,652.10
2010	01/24/2011	19	5,907.74	12/14/2010	19	1,836.08	12/14/2010	18	345.33	12/14/2010	18	1,166.95	01/24/2011	10	140.60	01/24/2011	18	792.34	01/24/2011	19	1,731.29
2011	01/03/2012	19	5,573.71	01/19/2012	19	1,689.37	01/03/2012	19	326.95	01/03/2012	18	1,096.85	01/03/2012	19	130.35	01/04/2012	18	744.34	01/04/2012	19	1,618.56
2012	01/24/2013	19	5,910.98	01/23/2013	19	1,767.01	01/22/2013	19	336.17	01/23/2013	19	1,135.74	01/24/2013	19	143.43	01/23/2013	19	800.30	01/24/2013	19	1,747.76
2013	01/07/2014	18	6,013.90	01/28/2014	19	1,824.33	01/07/2014	18	356.15	01/07/2014	18	1,198.20	01/02/2014	18	148.11	01/22/2014	19	819.30	01/02/2014	18	1,804.46
2014	01/07/2015	18	5,947.70	01/07/2015	19	1,807.89	01/07/2015	18	354.86	02/23/2015	19	1,155.05	02/16/2015	10	143.33	02/16/2015	19	758.96	02/16/2015	19	1,786.31
2015	01/04/2016	19	5,605.82	02/11/2016	19	1,686.20	01/04/2016	18	351.19	02/11/2016	19	1,104.57	02/13/2016	19	144.93	01/19/2016	19	689.28	02/15/2016	18	1,742.47
2016	12/15/2016	18	5,640.60	12/15/2016	18	1,651.10	12/15/2016	19	347.32	12/15/2016	18	1,117.15	12/16/2016	8	133.61	12/15/2016	19	692.87	12/15/2016	18	1,712.27
2017	01/05/2018	18	5,900.68	01/05/2018	19	1,715.44	01/05/2018	19	358.72	01/05/2018	18	1,143.20	01/06/2018	18	158.04	01/05/2018	19	718.15	01/02/2018	19	1,831.66
2018	01/21/2019	19	5,746.70	01/31/2019	19	1,638.64	01/31/2019	19	368.64	01/30/2019	19	1,157.29	03/10/2019	5	160.64	01/21/2019	19	733.01	01/21/2019	19	1,863.28
2019	12/19/2019	18	5,459.83	01/08/2020	19	1,581.19	12/11/2019	18	346.41	12/19/2019	18	1,061.67	12/19/2019	19	135.42	12/01/2019	18	681.62	12/19/2019	19	1,689.53
2020	12/16/2020	18	5,422.85	12/17/2020	18	1,560.88	12/16/2020	18	346.50	12/16/2020	18	1,085.38	02/12/2021	10	133.42	01/29/2021	19	672.59	12/16/2020	18	1,673.74
2021	01/11/2022	18	5,582.40	01/11/2022	18	1,591.80	01/11/2022	18	354.21	01/27/2022	9	1,081.17	01/21/2022	9	150.28	01/11/2022	18	721.76	01/11/2022	18	1,704.46
2022	02/03/2023	19	5,683.33	02/03/2023	19	1,569.23	02/03/2023	18	368.02	02/03/2023	19	1,115.08	02/03/2023	19	158.28	02/03/2023	19	738.98	02/03/2023	19	1,735.52
2023	01/20/2024	18	5,229.35	12/19/2023	18	1,632.50	01/17/2024	19	344.19	12/07/2023	10	1,022.92	01/21/2024	19	136.27	01/17/2024	18	702.62	01/21/2024	18	1,614.32
2024	01/08/2025	18	5,567.65	01/08/2025	19	1,661.63	01/21/2025	18	353.45	01/22/2025	8	1,100.48	01/08/2025	18	141.34	01/21/2025	18	743.38	12/23/2024	18	1,716.31

Appendix C: DER Cases

Electric Vehicles

The base, low, and high cases reflect sensitivity across two major components of the stock-flow model used for adoption forecasting, including: (1) stock growth, given that there is significant economic, demographic, and behavioral uncertainty influencing vehicle stock trends longer-term; (2) the ZEV share of new vehicle sales by year due to policy, behavioral, and compliance uncertainty as well as recent increased uncertainty around the impact of federal tariffs and tax credit repeals on consumer adoption. Other inputs into the stock-flow model, like scrap distributions and service life assumptions, are held constant across all cases. In addition to adoption sensitivities, the cases also reflect uncertainty in charging load assumptions. Most notably, unmanaged charging load profiles are leveraged for all vehicle types in the base and high cases; meanwhile, the low case incorporates managed charging profiles for all vehicle types to reflect the load curtailment that could arise from the implementation of a potential smart charging management program.[72] Key assumptions by case are below.

Base Case

The base case reflects the adoption and profile assumptions for each vehicle type outlined in the main body of the report.

High Case

The high case assumes faster customer adoption trends for all vehicle types and higher stock growth. Higher stock growth pathways for regional use vehicles (i.e., light-duty, school bus, and transit buses) are estimated using service-territory-level projections of number of households from Moody's upside 'S0' scenario. For the other vehicle types, stock growth is unchanged from the base case, which is essentially flat through the forecast horizon. On the policy front, the high case assumes the ZEV sales shares from the SEP Net Zero scenario (i.e., the most ambitious) and that the school bus mandate is achieved without any delays.[73] Finally, to capture additional upside potential, no impacts from tariffs and tax credit repeals are considered in this scenario. In this way, the high case represents a conceptual upper-bound on how fast EV adoption could occur, especially given recent federal policy developments and the fact that adoption is already lagging state targets.

Low Case

The low case assumes slower customer adoption trends for all vehicle types and lower stock growth. Analogous to the high case, lower stock growth pathways for regional use vehicles are estimated using Moody's downside 'S4' scenario; otherwise, for the other vehicle types, stock growth is held flat. On the policy side, a delayed ZEV sales shares from the SEP Current Policy scenario are used, reflecting

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[72] Note, a program of this type has not been implemented to date in a way that could feasibly achieve the managed charging impacts estimated in the low case. In this way, the charging impacts represent the upper bound of a potential future implementation that would require significantly more automated or 'smart' controls for managing load across the grid as well as other load modifiers beyond electric vehicles.

[73] Given similarities between the Net Zero and Additional Action scenarios, there is generally less upside shown for the light-duty segment compared to the other classes.

downside risk that the pace of adoption will fall further behind state targets. Delayed achievement of the school bus electrification mandate is also assumed. At the same time, higher prices from federal tariffs and greater consumer responsiveness in response to both tariffs and tax credit repeals are assumed to lead to an even bigger drag on EV adoption in the near- to medium-term. As noted above, the low case also incorporates managed charging profiles for all vehicle types. Assumptions on how many vehicles in each class will have access to either home or depot charging (for commercial and non-personal use vehicles) and what share will participate in a managed charging program are used alongside assumptions around the portion of load that can be managed to generate adjusted profiles. The managed charging profiles shift load from peak hours to off-peak hours, subject to reliability and participation factors, with the peak hour window shifting as necessary to ensure the managed profiles address peak loads.

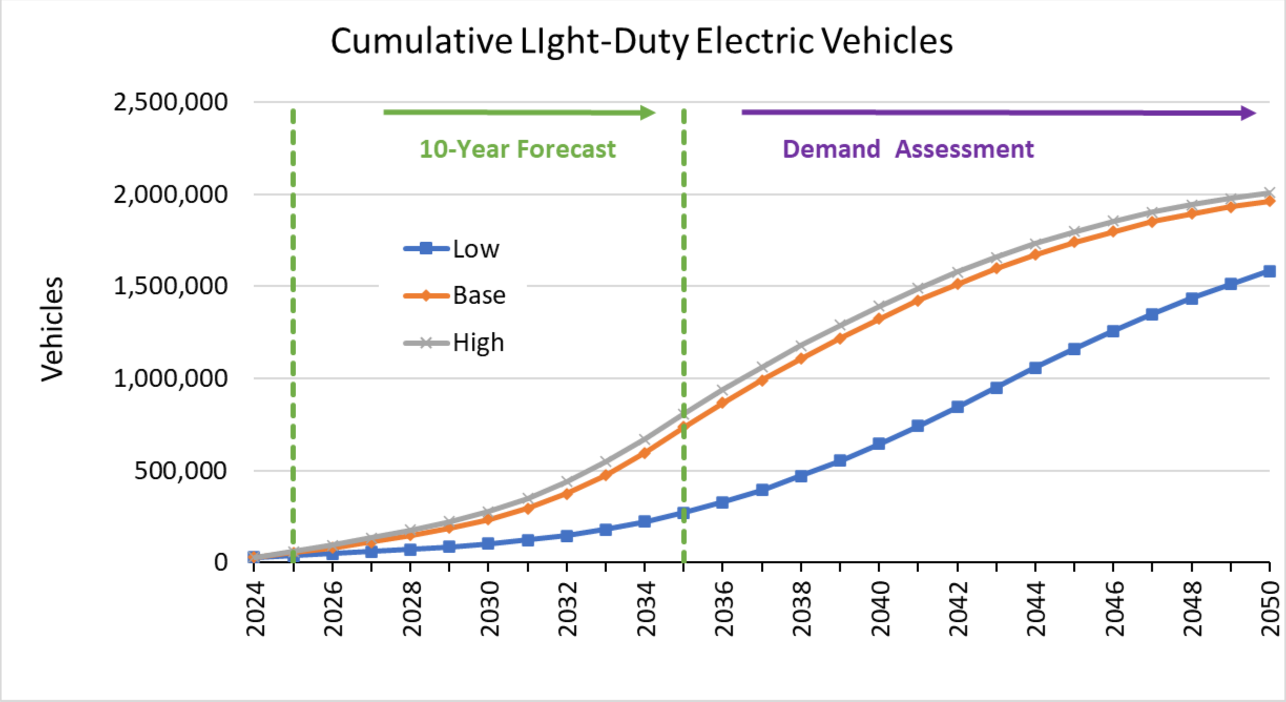

Figure 49: Cumulative LDEV Count

Table 2: Cumulative LDEV Count

Year	Low	Base	High
2024	28,127	28,127	28,127
2025	37,104	52,081	58,311
2026	46,972	79,083	92,950
2027	58,274	110,590	132,419
2028	71,144	147,016	175,339
2029	85,933	188,082	222,710
2030	102,092	233,016	275,561
2031	120,622	293,178	348,365
2032	145,651	372,502	439,556
2033	179,171	473,488	547,562
2034	222,346	596,913	670,680
2035	269,713	734,899	808,386
2036	327,357	866,228	939,120
2037	394,051	990,304	1,062,308
2038	468,887	1,107,906	1,178,625
2039	553,157	1,219,482	1,288,919
2040	645,497	1,324,778	1,392,811
2041	742,590	1,423,032	1,489,451
2042	844,008	1,513,893	1,578,454
2043	949,342	1,597,057	1,659,607
2044	1,058,237	1,672,391	1,732,335
2045	1,161,855	1,740,089	1,797,260
2046	1,259,309	1,799,506	1,854,054
2047	1,350,206	1,850,994	1,902,966
2048	1,434,279	1,894,796	1,944,369
2049	1,511,495	1,931,610	1,978,836
2050	1,583,101	1,963,658	2,008,718

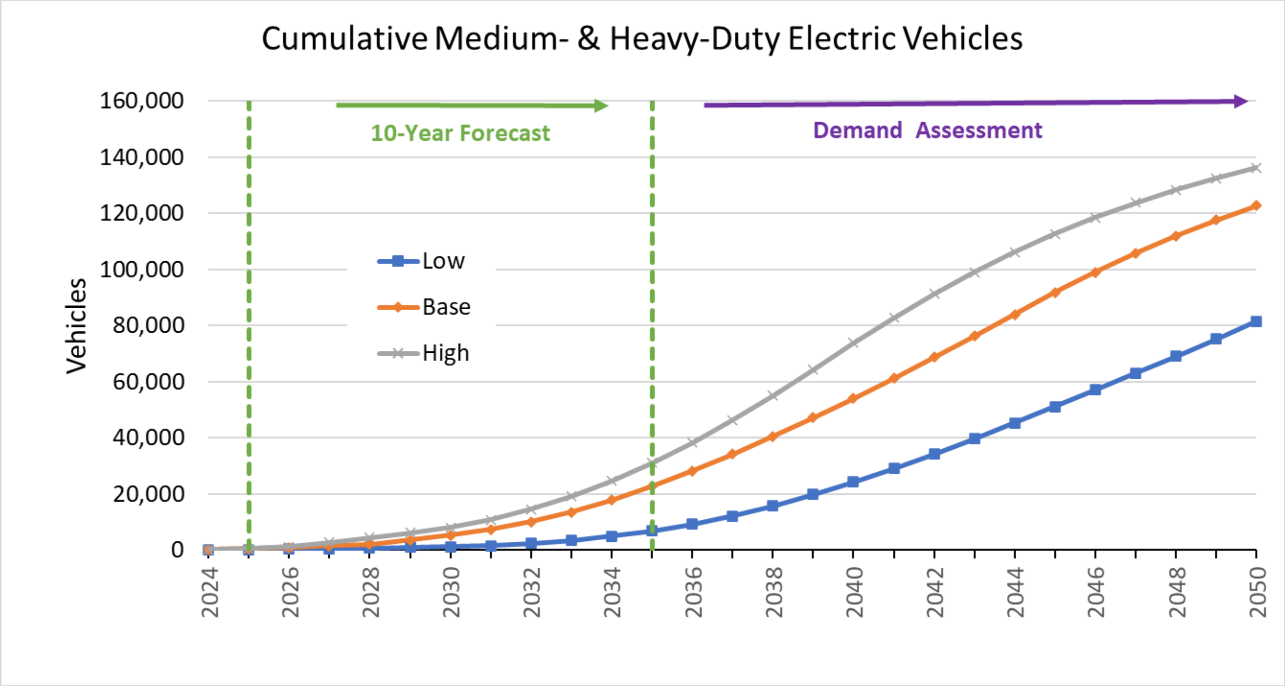

Figure 50: Cumulative MHDEV Count

Table 3: Cumulative MHDEV Cases (all types, including electric buses)

Year	Low	Base	High
2024	151	151	151
2025	292	511	598
2026	441	977	1,173
2027	611	1,534	2,849
2028	796	2,176	4,447
2029	994	3,663	6,124
2030	1,240	5,320	8,031
2031	1,542	7,411	10,842
2032	2,442	10,107	14,531
2033	3,552	13,552	19,123
2034	5,032	17,878	24,667
2035	6,829	22,793	31,118
2036	9,219	28,243	38,389
2037	12,214	34,185	46,411
2038	15,774	40,523	55,064
2039	19,849	47,193	64,252
2040	24,330	54,155	73,875
2041	29,168	61,334	82,872
2042	34,315	68,721	91,265
2043	39,735	76,288	99,026
2044	45,388	84,000	106,145
2045	51,182	91,816	112,625
2046	57,093	99,080	118,479
2047	63,098	105,800	123,736
2048	69,177	111,979	128,427
2049	75,328	117,617	132,589
2050	81,547	122,739	136,288

Electric Heat

The High and Low cases are presented to showcase uncertainty associated with heat-pump adoption arising from a combination of economic, demographic, technological, as well as market and policy related factors.

Base Case

The short-term adoption of heat-pumps is forecasted based on the Company's expected achievement of the NE: NY electrification goals through 2025 and EE/BE through 2030. Post 2030, projections based on analysis of the State's Energy Plan Additional Act scenario. Thus, the Company expects penetration to reach 16% by 2035 and 44% by 2050 for residential sector, whereas the commercial sector heat pump penetration is forecasted to reach 6% by 2034 and around 18% by 2050. By 2050, approximately 90% of the heat pump adoptions are expected to be categorized as full heat pumps with no backup supplemental fuels.

High Case

The high sensitivity models a case where state set higher goals as continued improvements in technology will support adoption of full heat-pumps that are suited to heat homes and businesses efficiently in cold climates. The high case also considers a slightly higher GSHP penetration than the base case. This case also assumes all heat pumps will be full heat pumps by 2050.

Low Case

The low case is designed to reflect slowed pathway for achievement of building electrification given the downside uncertainties around heat pump adoption. The low case assumes only 20%-30% of all residential and commercial customers use heat-pumps in 2050. The low case assumes about 90% of installed heat-pumps are full heat pumps, which is similar to the base case.

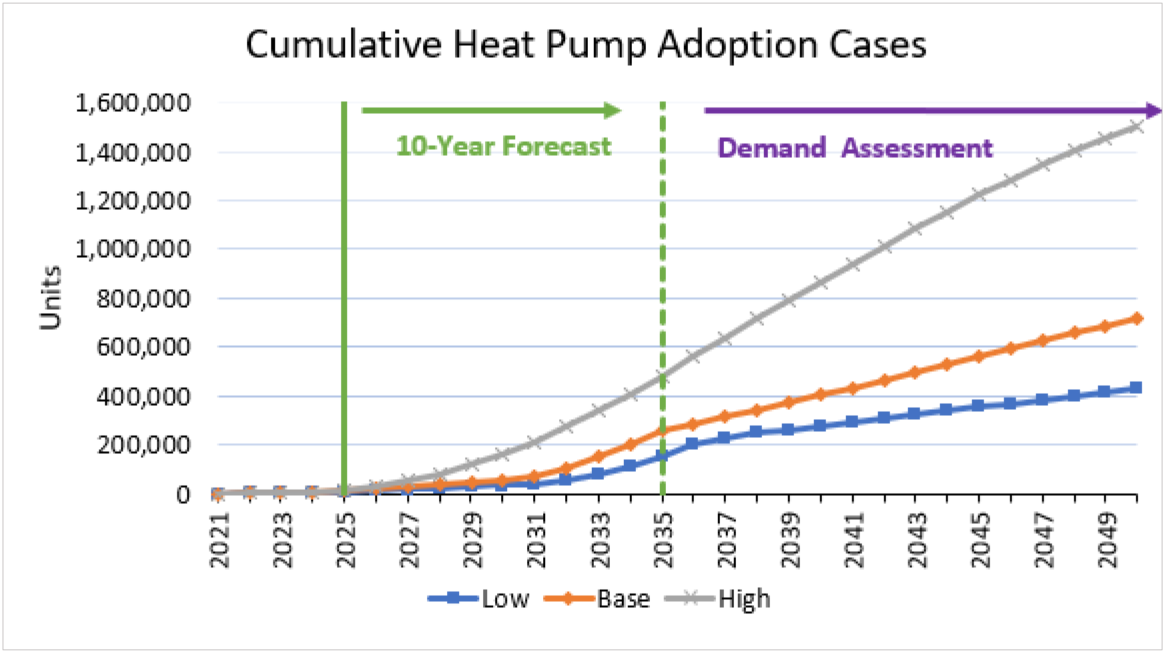

Figure 51: Cumulative Heat Pump Units

Table 4: Cumulative Heat Pump Units

Year	Low	Base	High
2022	2,899	2,899	2,899
2023	5,091	5,091	5,091
2024	6,735	6,735	6,735
2025	8,856	10,575	16,470
2026	13,019	18,521	33,262
2027	17,739	26,517	51,529
2028	22,684	34,516	80,509
2029	28,345	43,110	116,895
2030	34,272	51,820	159,926
2031	40,216	68,849	213,485
2032	52,501	101,522	273,005
2033	76,706	151,139	338,877
2034	112,630	203,529	409,321
2035	153,557	259,237	483,913
2036	199,462	286,644	562,081
2037	229,397	313,953	639,587
2038	247,352	343,099	716,058
2039	262,863	372,748	791,920
2040	278,467	402,813	866,926
2041	294,057	433,342	941,038
2042	309,526	465,672	1,014,043

2043	324,736	499,261	1,085,523
2044	339,605	532,608	1,154,903
2045	354,042	565,369	1,221,780
2046	368,109	597,277	1,285,697
2047	382,372	628,281	1,346,379
2048	396,938	658,423	1,403,412
2049	412,013	687,776	1,456,305
2050	428,092	715,969	1,504,622

In addition to reflecting uncertainty in heat pump adoption/penetration, the Company also models uncertainty resulting from heat pump performance. The sensitivity associated with performance is captured by developing heat pump profiles under base, high, and low COP assumptions. As noted above, the base case COP curve is adopted from MA DOER. To develop sensitivities around the base curve, the Company referred to a report published by RDH Building Science Inc, titled, 'BC Cold Climate Heat Pump study'.[74] The study analysed the heating season performance of a small sample of heat-pumps in the cold and moderate climate regions of British Columbia. Their analysis was based on the observed behavior of limited number of homes with heat-pumps, and on the technology that exists today. As such, the high COP curves in the Company's models assume potential technological upgrades would enhance heat-pump operation over and above what was observed in the BC Study, especially during relatively cold outdoor conditions.

On the other side, the heating capacity of the system could drop considerably at low outdoor temperatures, causing the COP curve to be more elastic to temperature changes than in the base case and a switch over to resistance heating much sooner than in the base case. This is reflected in the low COP curve. The chart below compares the three COP cases for a full ASHP.

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[74] https://www.rdh.com/wp-content/uploads/2021/01/BC-Cold-Climate-Heat-Pump-Study-Final-Report.pdf

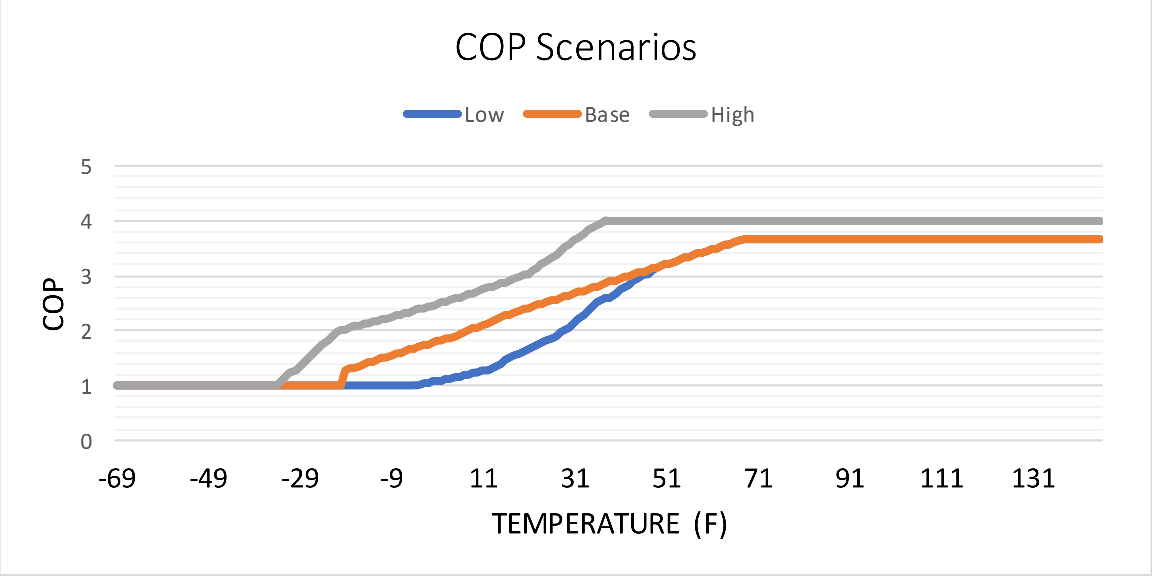

Figure 52: COP Curves by DER Cases

The PHPs also assume same COP curve as full ASHP up to 30F but switches to back-up fuel at 30F or lower temperatures under all three scenarios. The GSHPs are assumed to be inelastic to temperature changes. However, a slight variation in their COP is assumed under the three scenarios – operating at COP of 4, 4.8 and 3.66 under base, high, and low COP cases respectively.

Energy Efficiency

The High and Low cases are presented to showcase uncertainty associated with EE savings. All EE savings are in adjusted gross terms. Any savings from heat pumps and demand response programs are removed as they are projected separately in their own category.

Base Case

As described above, the base case is tied to Company plans outlined in NE:NY order through 2025 and its proposed plan in the EE/BE filing through 2030. Beyond 2030, the base case assumes annual savings for both residential and commercial are held constant, before slowing in the last decade of the demand assessment period. Additional savings are assumed in both residential and commercial sector from organic EE savings not captured in the Company's EE plans.

High Case

The high case assumes higher annual incremental savings for residential and commercial sectors, reflecting the observed variance in actual savings from past projections and the potential for greater funding and customer adoption.

Low Case

The low case assumes lower annual incremental savings for residential and commercial sectors, reflecting the observed variance in actual savings from past projections and the potential for lower funding and customer adoption.

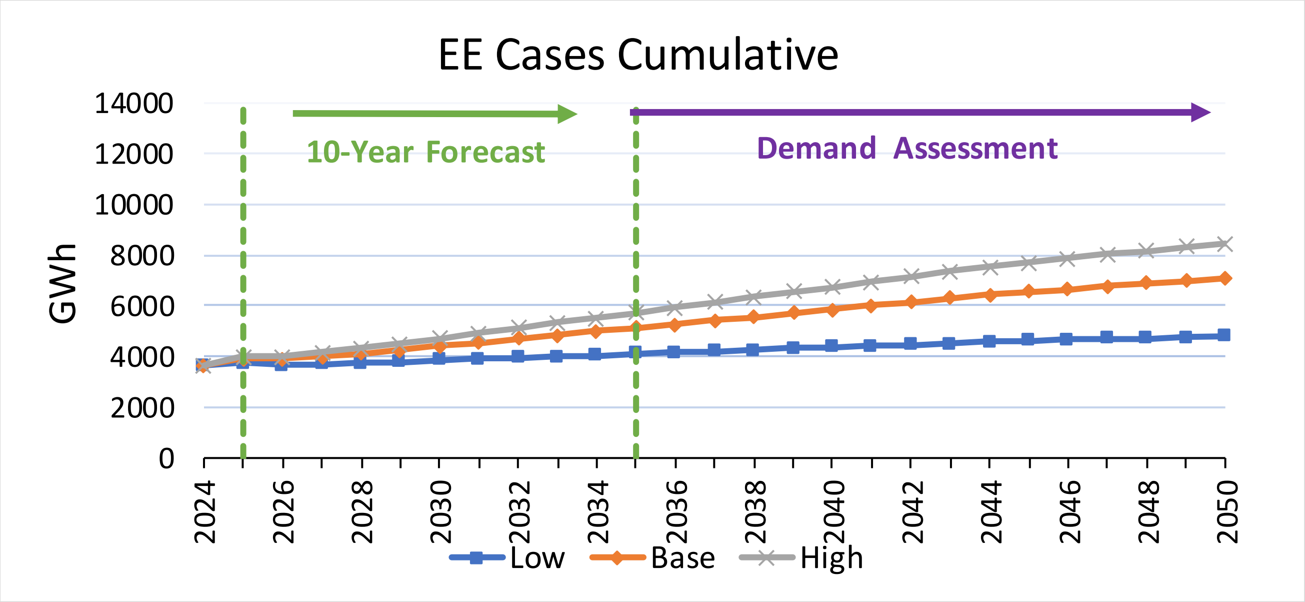

Figure 53: Cumulative EE Annual Saving

Table 5: Cumulative Energy Efficiency Annual Saving (GWh)

Year	Low	Base	High
2024	3,653	3,654	3,653
2025	3,727	3,907	4,013
2026	3,671	3,892	4,010
2027	3,711	4,003	4,162
2028	3,753	4,124	4,329
2029	3,800	4,257	4,513
2030	3,852	4,403	4,717
2031	3,904	4,549	4,921
2032	3,955	4,695	5,124
2033	4,007	4,841	5,328
2034	4,058	4,987	5,531
2035	4,110	5,133	5,735
2036	4,161	5,279	5,939
2037	4,213	5,425	6,142
2038	4,265	5,571	6,346
2039	4,316	5,717	6,550
2040	4,368	5,864	6,753
2041	4,419	6,010	6,957
2042	4,471	6,156	7,160
2043	4,520	6,294	7,354
2044	4,567	6,426	7,538
2045	4,611	6,551	7,712
2046	4,653	6,670	7,878
2047	4,693	6,783	8,036
2048	4,731	6,891	8,185
2049	4,767	6,993	8,327
2050	4,801	7,090	8,463

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Solar – Photovoltaic

Base Case

Sensitivities around the PV base case were produced to account for forecasting uncertainty. As previously described, the base case projections in the near-term are based on the historical rate of connection and SME consensus on estimated realization of the queue. For 2026 and beyond, projections are tied to the Additional Action scenario from New York's Draft State Energy Plan, which includes zonal breakdowns of the state-wide installation target for PV capacity of 10,000 MW in 2030.

High Case

The high case is based on higher connections in the short-term and is tied to the Additional Action (Constrained Build) scenario outlined in New York's Draft Energy Plan, which shows a greater amount of distributed solar capacity compared to the Additional Action scenario.

Low Case

The low case depicts a fewer number of connections in the short-term which is based on recent observed variability between past forecasts and actual realized connections. In the long-term, the low case is based on a ten-year delay to the capacity projections outlined in the Additional Action scenario.

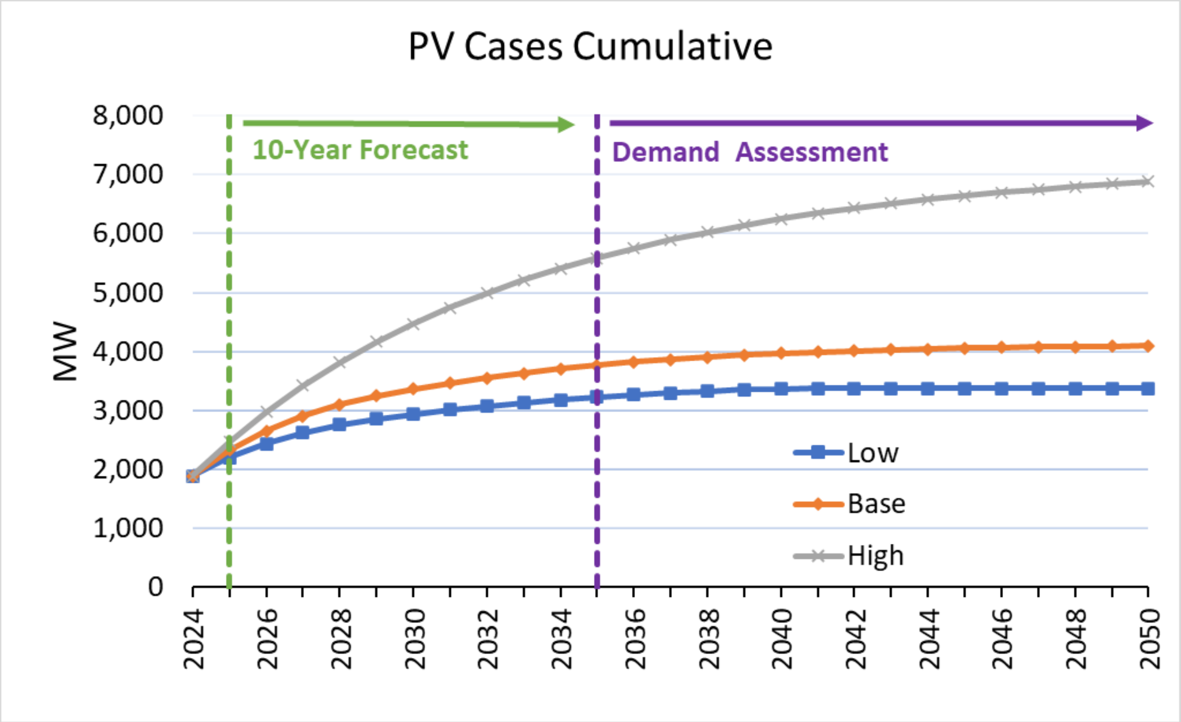

Figure 54: Cumulative PV MW Nameplate Capacity

Table 6: Cumulative PV MW Nameplate Capacity

Year	Low	Base	High
2024	1,895	1,895	1,895
2025	2,206	2,326	2,471
2026	2,442	2,656	2,978
2027	2,621	2,909	3,424
2028	2,757	3,102	3,816
2029	2,860	3,250	4,162
2030	2,938	3,363	4,466
2031	3,009	3,463	4,739
2032	3,072	3,553	4,985
2033	3,129	3,633	5,207
2034	3,181	3,704	5,406
2035	3,227	3,767	5,586
2036	3,266	3,820	5,747
2037	3,300	3,866	5,893
2038	3,328	3,905	6,024
2039	3,352	3,938	6,141
2040	3,365	3,966	6,247
2041	3,372	3,989	6,343
2042	3,375	4,010	6,429
2043	3,376	4,027	6,506
2044	3,377	4,041	6,575
2045	3,378	4,054	6,638
2046	3,378	4,064	6,696
2047	3,378	4,073	6,749
2048	3,378	4,081	6,797
2049	3,378	4,088	6,842
2050	3,378	4,093	6,883

Energy Storage

Base Case

Sensitivities around the ES base case were produced to account for forecasting uncertainty. As previously described, the base case projections are based on the historical rate, subject-matter expert (SME) consensus, state targets, and the Additional Action scenario outlined in the NY Draft State Energy Plan. About 17-24% of the state targets and decarbonization goals are assumed to impact demand on the electrical distribution system rather than participate in wholesale transmission markets.

High Case

The higher case depicts a greater number of connections in the short term which is based on recent observed variability between past forecasts and actual realized connections. In the long-term, the high case is based on another Net Zero A scenario in the NY State Draft Energy Plan, which depicts a higher amount of ES capacity compared to the Additional Action scenario. This case also assumes a slightly higher share of ES capacity on the distribution system.

Low Case

The low case depicts a fewer number of connections in the short term which is based on recent observed variability between past forecasts and actual realized connections. In the long-term, the low case assumes only 10% of the Additional Action scenario targets impact the Company's distribution system.

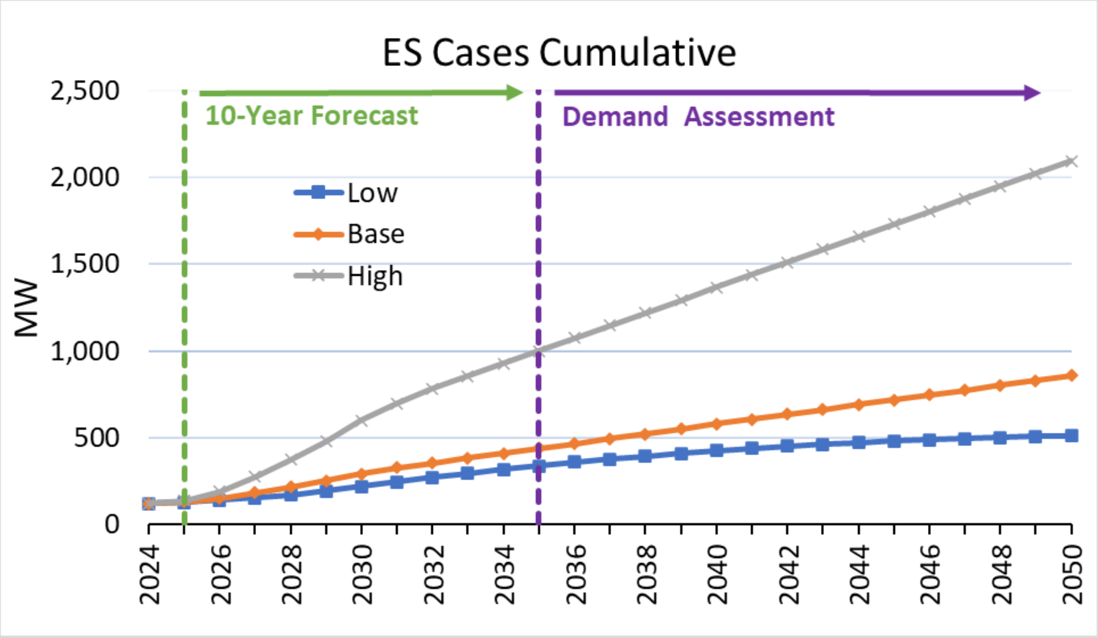

Figure 55: Cumulative Energy Storage Nameplate Capacity

Table 7: Cumulative Energy Storage MW Nameplate Capacity

Year	Low	Base	High
2024	119	119	119
2025	128	131	137
2026	139	151	191
2027	153	182	276
2028	170	215	373
2029	192	252	479
2030	220	292	599
2031	246	326	696
2032	271	354	781
2033	295	382	854
2034	317	410	927
2035	338	438	1,000
2036	358	466	1,073
2037	377	494	1,146
2038	394	522	1,219
2039	410	550	1,292
2040	425	578	1,365
2041	438	606	1,438
2042	450	634	1,511
2043	461	662	1,584
2044	471	690	1,657
2045	480	718	1,730
2046	488	746	1,803
2047	495	774	1,876
2048	501	802	1,949
2049	507	830	2,022
2050	512	858	2,095

Demand Response

Base Case

The base case reflects the adoption and profile assumptions by customer program type as outlined in the main body of the report.

High Case

Under the high DR case, incremental growth is assumed to be 25% than the base case for the residential thermostats and commercial programs. The degree of uncertainty reflected is informed by guidance provided by the Company’s DR SMEs & Program Administrators.

Low Case

For the low DR case, no additional incremental MW is assumed for any programs, effectively keeping MW peak impact flat throughout the forecast and demand assessment horizon. The low case essentially assumes the Company’s programs have achieved their market potential, saturating sooner than previously expected.

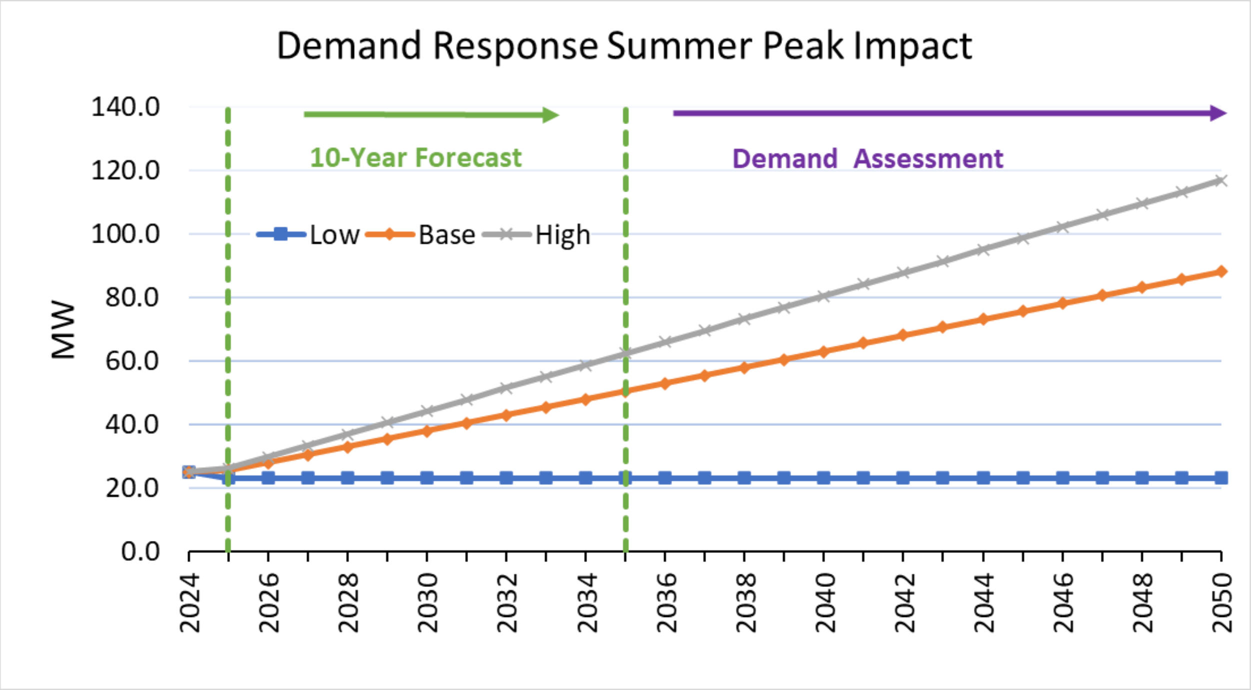

Figure 56: Annual Cumulative DR Impact

Table 8: Annual Cumulative DR Impact (MW)

Year	Low	Base	High
2024	25.2	25.2	25.2
2025	23.3	25.7	26.3
2026	23.3	28.1	29.8
2027	23.3	30.6	33.4
2028	23.3	33.1	37.0
2029	23.3	35.6	40.6
2030	23.3	38.1	44.3
2031	23.3	40.6	47.9
2032	23.3	43.1	51.5
2033	23.3	45.6	55.1
2034	23.3	48.1	58.8
2035	23.3	50.6	62.4
2036	23.3	53.1	66.0
2037	23.3	55.6	69.6
2038	23.3	58.1	73.3
2039	23.3	60.6	76.9
2040	23.3	63.1	80.5
2041	23.3	65.6	84.1
2042	23.3	68.1	87.8
2043	23.3	70.6	91.4
2044	23.3	73.1	95.0
2045	23.3	75.6	98.6
2046	23.3	78.1	102.3
2047	23.3	80.6	105.9
2048	23.3	83.1	109.5
2049	23.3	85.6	113.1
2050	23.3	88.1	116.8

Appendix D: Typical Day 24-hour Load Profiles

Typical day load profile of each month is derived from the median of the 50th load hour by hour of days in the month. Typical weekdays include all weekdays in the month except for holidays. Typical weekend days include weekend days and holidays. Figures 57 and 58 present the typical weekday and typical weekend days profiles by month for selected years for MECO and NANT, respectively.

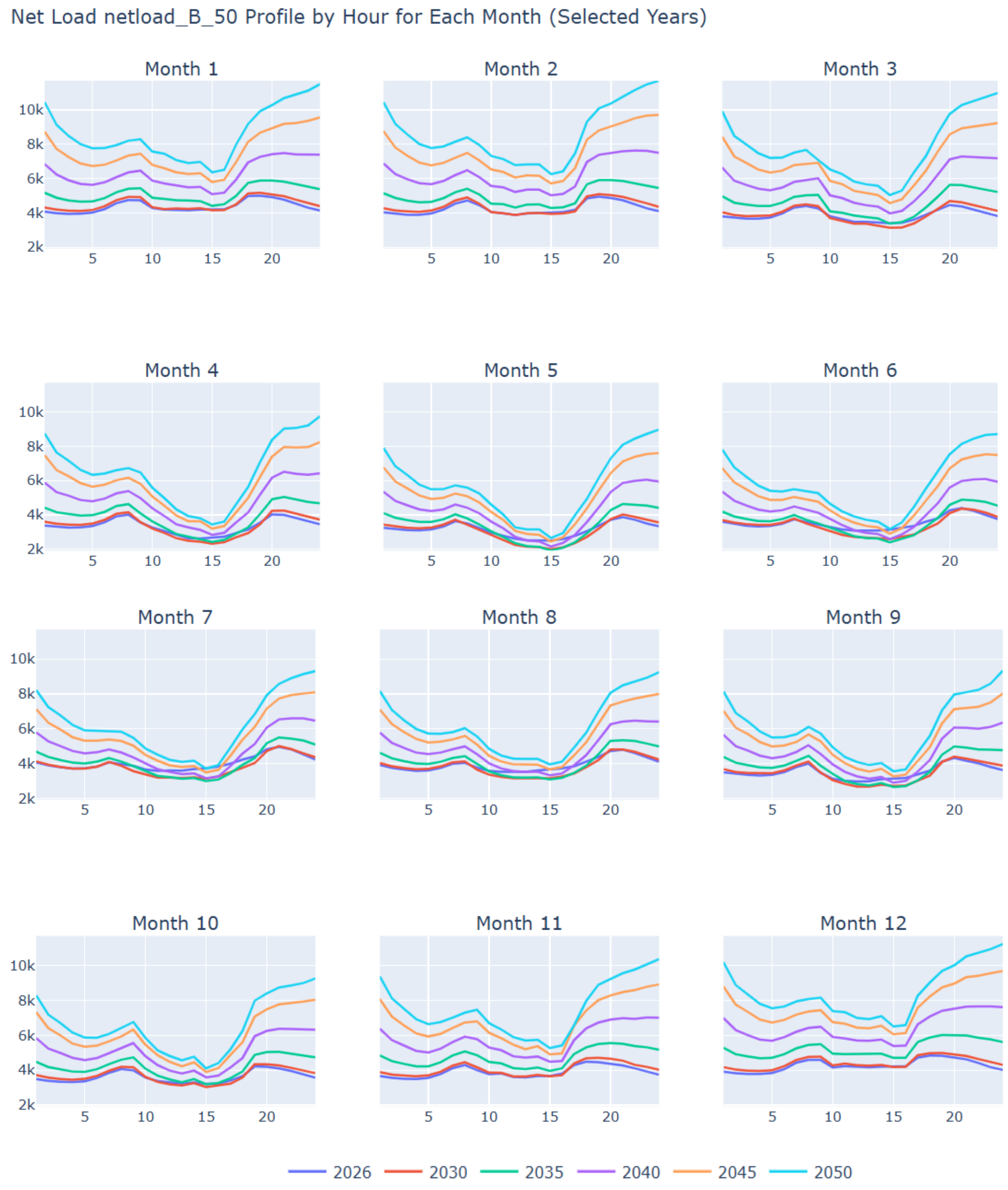

Figure 57: Typical Weekday Profiles

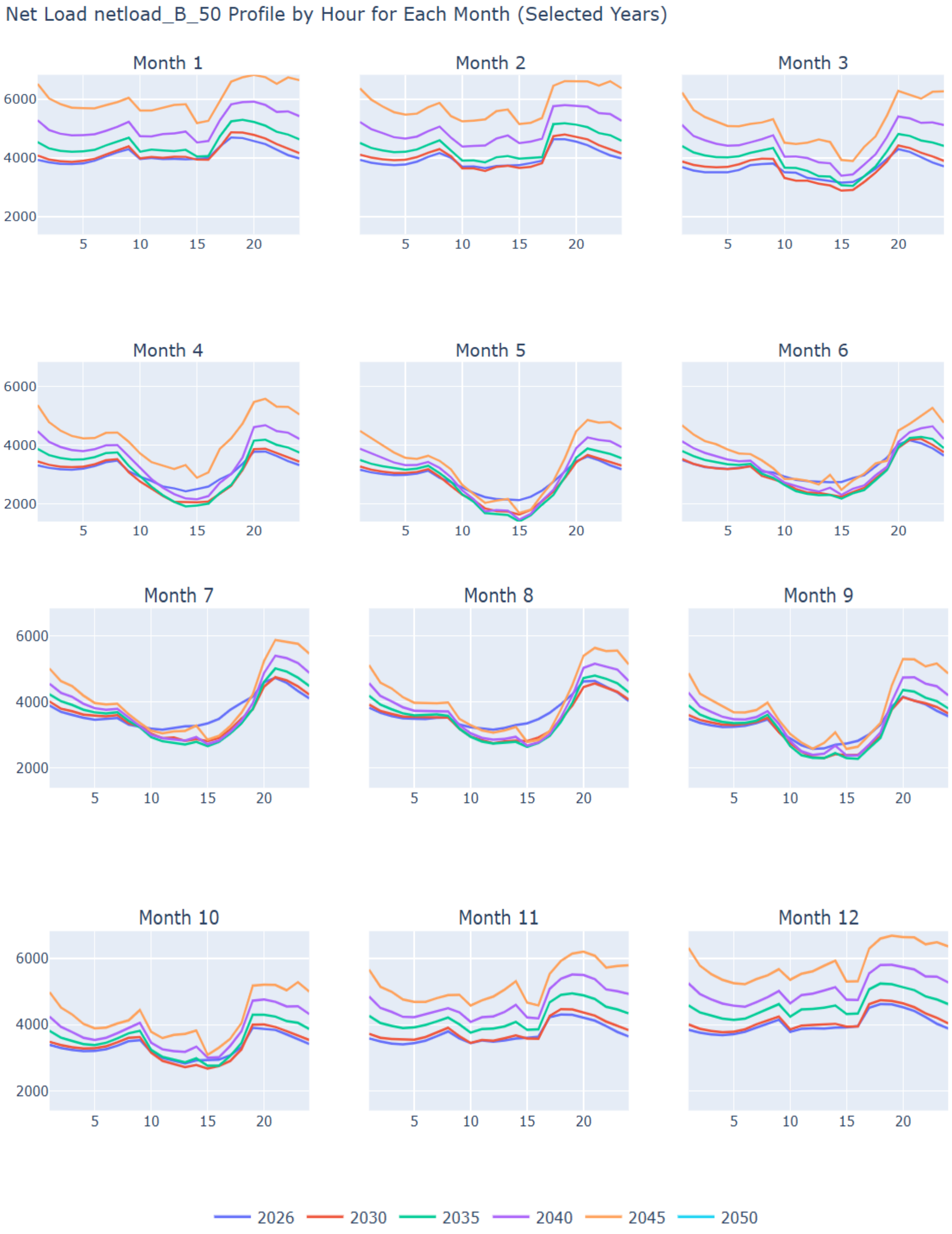

Figure 58: Typical Weekend Days Profiles

Appendix E: List of Input Data

Section	Data Inputs	Source of Data	Used By
3.1.1	Historical hourly zonal load	ISO settled data: Jan 2003 to March 2025 Company internal preliminary data: April 2025 to August 2025	Baseload forecasting
3.1.1	Historical weather	DTN	Baseload forecasting
3.1.1	Class average load shape	Company Portal[75]	Baseload forecasting
3.1.2	Economic data	Moody's Analytics	Baseload forecasting
3.2.1	Historical vehicle in-operation (VIO) counts	S&P Global's VIO/Mobility Data NY DMV Registration Database	Netload forecasting (cumulative DER impacts)
3.2.1	Electric vehicle-in-operation (VIO) projections	NY Draft SEP California Advanced Clean Car II (ACC II) rules and regulations California Advanced Clean Trucks (ACT) rules and regulations Moody's Analytics Household Projections BloombergNEF's 2025 EV Outlook	Netload forecasting (cumulative DER impacts)
3.2.1	Electric vehicle charging load profiles	ISO-NE (LDEV charging load profile shape, battery-temperature functions, annual VMT for regional vehicle types, day-type effects) NYISO (monthly LDV VMT allocation) BloombergNEF's 2025 EV Outlook (medium- and heavy-duty VMT growth projections) U.S. EIA's 2025 AEO (LDV VMT growth & historical MHD VMT trends) NREL's EVI Pro-Lite tool (charging and energy shares by location for LDEVs) 2022 Electric Highways Study (public charging load profile shapes for tractor trucks and other types of MHDVs)	Electric vehicle charging load profiles

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[75] Load Profiles | Supply Costs | National Grid (nationalgridus.com)

		Internal load assessment studies and analysis conducted with industry partners and informed by the data from CALSTART, Hitachi Energy, and the Vehicle Inventory and Use Survey (VIUS) (MHDEV depot charging load profiles as well as battery-temperature relationship assumptions)	
3.2.1	Fleet depot and public charging sites database	Federal Motor Carrier and Safety Administration (FMCSA) fleet census data NY DEC One-Time ACT Reporting Fleet Survey EPRI's eRoadmap tool Hitachi Fleet Cluster and Mega-Cluster Studies Federal Highway Administration (FHWA) truck stop and parking data 2024 U.S. Freight Corridor Study World Resources Institute (WRI) school district bus fleet data NYS DOT school bus registration data NYSERDA school bus survey data U.S. Environmental Protection Agency (EPA) database of underground storage tank (UST) facilities for site identification 2022 Electric Highways Study ElectroTempo depot study Make-Ready Program (MRP) applications Company's Fleet Assessment Services Program (FASP) Public information on electrification plans, fleet locations, and fleet characteristics Other internal analyses and data related to load assessments, clusters studies, and National Grid's own operational fleet	Net load forecasting (cumulative DER impacts)

3.2.1	Secondary allocation measures for MHDEV feeder-level allocation (depot and public charging)	S&P Global's VIO/Mobility data by ZIP code and MHDV type C&I energy consumption by feeder from Company's internal billing and premises data U.S. Highway Performance Monitoring System (HPMS) vehicle miles traveled for all vehicles and tractor trucks U.S. Environmental Protection Agency (EPA) database of underground storage tank (UST) facilities for capacity measures Federal Highway Administration (FHWA) truck stop and parking data	Net load forecasting (cumulative DER impacts)
3.2.2	Historical electric heat pumps counts (Company program)	Company Internal	Netload forecasting (cumulative DER impacts)
3.2.2	Electric heat pump counts projection	New Efficiency New York Order [76] Energy Efficiency and Building Electrification Order (EE/BE) [77] Drafted State Energy Plan (SEP) U.S. Census Data	Netload forecasting (cumulative DER impacts)
3.2.2	Electric heat pump load profile	NREL Restock and Comstock building data[78]	Net load forecasting (cumulative DER impacts)
3.2.2	Electric heat pump coefficient of performance (COP)	Massachusetts DOER	Net load forecasting (cumulative DER impacts)
3.2.3	Historical energy efficiency energy savings	Company Internal	Baseload forecasting (historical data disaggregation) Netload forecasting (cumulative DER impacts)
3.2.3	Energy efficiency projection	New Efficiency New York Order Energy Efficiency and Building Electrification Order (EE/BE)	Netload forecasting (cumulative DER impacts)

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[76] Order Authorizing Utility Energy Efficiency and Building Electrification Portfolios through 2025, dated January 16, 2020, Case 18-M-004. The impact of new Order (for period 2026-2030) are not considered in these forecasts.
[77] New Order "EE/BE" Energy Efficiency and Building Electrification for 2026-2030, CASE 18-M-0084 and Case 14-M-0094.
[78] https://resstock.nrel.gov/, https://www.nrel.gov/buildings/comstock.html

3.2.3	Energy efficiency profile	NREL Restock and Comstock building data	Net load forecasting (cumulative DER impacts)
3.2.4	Historical solar PV installed nameplate capacity	Company Internal	Baseload forecasting (historical data disaggregation) Netload forecasting (cumulative DER impacts)
3.2.4	Solar PV nameplate capacity projection	Historical trend CLCPA U.S. Census Data Customer energy usage NYISO Goldbook GridTwin[79]	Netload forecasting (cumulative DER impacts)
3.2.4	Solar PV load profile	PVWatts[80]	Net load forecasting (cumulative DER impacts)
3.2.4	Historical Solar Irradiance (part 1)	National Solar Radiation Database (NSRDB)[81]	Net load forecasting (cumulative DER impacts)
3.2.4	Historical Solar Irradiance (part 2)	Solcast Weather Database	Net load forecasting (cumulative DER impacts)
3.2.5	Historical energy storage installed nameplate capacity	Company Internal	Netload forecasting (cumulative DER impacts)
3.2.5	Energy storage capacity projection	CLCPA, Energy Storage Roadmap, and Coordinated Grid Planning Process, State and Utility Storage Interconnection Queues	Netload forecasting (cumulative DER impacts)
3.2.6	Energy storage charging and discharging load profile	SME	Netload forecasting (cumulative DER impacts)
3.2.6	Historical demand response (Company program)	Company Internal	Baseload forecasting (historical data disaggregation)

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[79] https://home.gridtwin.com/

[80] https://pvwatts.nrel.gov/

[81] The National Solar Radiation Database (NSRDB) https://nsrdb.nrel.gov/

			Netload forecasting (cumulative DER impacts)
3.2.6	Demand response projections	Program Administrator approved targets	Net load forecasting (cumulative DER impacts)
3.2.6	Demand response relative profile shapes	Historical performance data from the NY C&I Commercial System Relief Program (CSRP) Historical performance data from the Company’s residential gas thermostats program	Net load forecasting (cumulative DER impacts)

Appendix F: List of Major Changes and Enhancements

Component	
Net Load	Introducing typical day profiles by month
Energy efficiency	Refined EE savings End-Use share based on longer historical years and planned EE programs measurement level saving.
Solar PV	Refined PVWatts Solar PV simulation system configuration based on benchmark with actual generation data as well as SME empirical judgement.
Electric heat pump	Refined forecast by adding adjustments for the Tariff and All-Electric Building Act.
Electric vehicle	Refined light-duty electric vehicle propensity model with the latest ACS data as well as the most up-to-date vehicle registration records from DMV. System-level adoption forecast updated to reflect NY SEP scenarios as well as impacts from federal tariffs and tax incentives repeals; stock-flow modeling framework revamped to incorporate scrap curves and service life expectations more directly for each vehicle type; refined treatment of Class 2B vehicles to better reflect relevant policy constraints Historical vehicle miles traveled (VMT) updated for medium- and heavy-duty vehicles; charging load shape updated for school buses Medium- and heavy-duty fleet depot database expanded using latest fleet assessments and information on National Grid fleets
Demand Response	Load profiles updated using latest program data