New York's Grid Flexibility Potential

VOLUME III: SUPPLEMENTAL ANALYSIS

PREPARED BY

Ryan Hledik
Akhilesh Ramakrishnan
Goksin Kavlak
Kate Peters
Sophie Edelman
Alison Savage Brooks

MARCH 2025

Brattle

NOTICE

This report was prepared by The Brattle Group for New York State Energy Research and Development Authority (NYSERDA) and The New York Department of Public Service (DPS). It is intended to be read and used as a whole and not in parts. The report reflects the analyses and opinions of the authors and does not necessarily reflect those of The Brattle Group's clients or other consultants.

The authors would like to thank the NY DPS team for their invaluable insight and leadership throughout this study, including Robert Cully, Chris Graves, Zeryai Hagos, Schuyler Matteson, Stephanie McDermott, Randy Monica Jr., Andrew Owens, and Marco Padula. We are similarly grateful to the NYSERDA team, including Hafiz Bello, Seth Berkman, and Ashish Tiwari.

We also would like to thank DNV for their valuable and significant contributions to the analysis, which focused on developing the baseline characterization of the New York market. Key DNV contributors to that research were Kelly Marrin, Teague Douglas, Nick Posawatz, and Karen Cramton.

TABLE OF CONTENTS

I. Introduction 1

II. Illustrating Hourly Grid Flexibility Dispatch 3

A. Winter Peak Day 3

B. Summer Peak Day 4

C. Average Winter and Summer Days 5

D. Alternative Dispatch Strategies 7

III. Grid Flexibility Potential Sensitivity Analysis 8

A. Approach Overview 8

B. Results 10

IV. Additional Grid Flexibility Options 14

A. Medium and Heavy-Duty Vehicle Managed and Bidirectional Charging 14

B. Front-of-the-Meter Distributed Energy Storage 17

C. Energy Efficiency 19

D. Customer Load Management Systems 22

E. Thermal Energy Networks and Thermal Energy Storage 24

F. Large New Loads with Microgrids 26

V. Grid Flexibility Considerations for Low Income Customers and Disadvantaged Communities 27

A. The Importance of a Tailored Approach for DAC Participation 28

B. Potential Features of a Tailored Approach 29

C. Information Needs for Assessing Grid Flexibility Potential for Low-Income and Disadvantaged Communities 32

VI. Appendix A: Sensitivity Analysis Details 33

A. Participation 33

B. Eligibility 34

C. Program Operational Characteristics 37

D. Avoided Generation Capacity Cost 38

E. Distribution Capacity Threshold 39

F. Avoided Cost Allocation Hours 39
G. Program Costs 40

I. Introduction

In April 2024, the New York Public Service Commission (NY PSC) issued an Order initiating the Grid of the Future proceeding. According to the Order, the objective of the Grid of the Future proceeding is "to unlock innovation and investment to deploy flexible resources – such as distributed energy resources (DERs) and virtual power plants (VPPs) – to achieve our clean energy goals at a manageable cost and at the highest levels of reliability."[1]

The Order defines grid flexibility as "the grid's ability to shift either demand or supply to meet bulk power system and/or local distribution needs."[2] In this context, "flexible demand" includes options such as time-varying rates, demand response from end-uses such as heating/cooling, and electric vehicle (EV) managed charging, among others. "Flexible supply" includes EV discharging through vehicle-to-grid capability, or discharging from stationary energy storage, for example.

Among several requirements, the Order directs the NY Department of Public Service (DPS) Staff to conduct a Grid Flexibility Potential Study ("Study"). The Study should: "(1) assess the present and potential future capabilities of flexible resources; (2) identify, characterize, and recommend means and methods for effectively integrating flexible resources into grid planning and operations under a range of different scenarios; and (3) recommend near term actions to better deploy identified resources."[3]

The NY DPS Staff filed the Grid Flexibility Potential Study in January 2025.[4] That study, developed by The Brattle Group with contributions from DNV, consisted of two volumes. Volume I (Summary Report) described the findings of the study and documented key methodological considerations behind the analysis.[5] Volume II (Technical Appendix) provided more detail on the modeling and stakeholder engagement behind the study.[6]

During the development of the Grid Flexibility Potential Study, stakeholders and DPS Staff identified four additional areas of research interest which, while beyond DPS Staff's scope of work for the Study, were determined to significantly enhance the findings. The purpose of this third volume of the report is to

1 Case 24-E-0165, Grid of the Future Proceeding, Order Instituting Proceeding (issued April 18, 2024)., p. 3.

2 Order Instituting Proceeding, p. 6.

3 Order Instituting Proceeding, p. 13.

4 Case 24-E-0165, Grid of the Future Proceeding, Grid Flexibility Potential Study Phase 1 Final Report (filed January 31, 2025).

5 Case 24-E-0165, Grid of the Future Proceeding, Grid Flexibility Potential Study Phase 1 Final Report – Vol. I – Summary Report (filed January 31, 2025).

6 Case 24-E-0165, Grid of the Future Proceeding, Grid Flexibility Potential Study Phase 1 Final Report – Vol. II – Technical Appendix (filed January 31, 2025).

summarize the supplemental analysis that was conducted in those areas. Each of the four areas is addressed in the remaining sections of this report:

1. **Illustrating hourly grid flexibility dispatch.** The modeling for the Grid Flexibility Potential Study included hourly granularity when accounting for the operation of grid flexibility options and their value to the New York power system. The hourly dispatch of the options will vary from day to day depending on the needs of the power system and the highest value opportunities to use grid flexibility. In Section II of this report, we illustrate how the portfolio of grid flexibility measures modeled for the Grid Flexibility Potential Study could be dispatched to provide value across peak and average load days in the summer and winter.

2. **Sensitivity analysis.** Volume I of the Grid Flexibility Potential Study presented estimates of grid flexibility potential under a set of base case assumptions.[7] Given that uncertainty is inherent in any forward-looking assessment of the New York power system, it is important to understand the extent to which the Study's findings are sensitive to alternative assumptions. In Section III of this report, we describe the results of a range of sensitivity cases. Appendix A provides further detail behind the sensitivity case definitions.

3. **Additional grid flexibility technologies.** As described in Volume I, the scope of the grid flexibility potential analysis focused on "options that are dispatchable, behind the customer's meter, and have sufficient empirical support for quantitative modeling based on full-scale deployments or rigorous piloting."[8] However, additional grid flexibility options may fall within the scope of the broader Grid of the Future proceeding and contribute to grid flexibility potential beyond the estimates in the Study. In Section IV of this report, we describe those additional options, the future role that they could play in addressing the New York power system's flexibility needs, and unique barriers limiting their deployment.

4. **Considerations for low-income customers and disadvantaged communities.** New York's policy goals include a focus that the policies benefit low-to-moderate income (LMI) customers and disadvantaged communities (DAC). In Section V of this report, we discuss challenges that may prevent LMI and DAC segments from benefitting from grid flexibility and options for addressing those challenges. We also identify additional data that would be needed to extend a future iteration of the Grid Flexibility Potential Study to quantify opportunities for these customer segments.

---

[7] The Volume I report also included one sensitivity case, focused on the sensitivity of the results to changes in the assumed marginal cost of generation capacity.

[8] Grid Flexibility Potential Study Phase 1 Final Report – Vol. I – Summary Report., p. 5.

II. Illustrating Hourly Grid Flexibility Dispatch

The Volume I report showed that New York's cost-effective grid flexibility potential could amount to 8.5 gigawatts (GW) by 2040. When used to address a range of system needs throughout the year, that flexibility could avoid nearly $3 billion/year in system resource costs, with the vast majority of those avoided costs being returned to customers as either grid flexibility participation payments or a retail rate reduction.

While the Volume I report focused on reporting the potential capability of the grid flexibility portfolio during the hours of the system peak, the underlying analysis found that the portfolio could be used year-round in order to provide the reported system benefits.[9] For example, grid flexibility options with the ability to be dispatched on a frequent basis, such as batteries, could operate not only on peak load days to provide capacity benefits, but also on other days with more average load conditions to provide energy benefits.

To provide a more nuanced view of the potential operational profile of grid flexibility technologies under a range of system conditions, this section of the report illustrates example hourly dispatch for a peak load and average load day in both the summer and winter. As a use case, we simulate the dispatch of the grid flexibility portfolio[10] to reduce statewide net load[11] on each example day. This use case primarily illustrates how grid flexibility would be used to provide resource adequacy and energy value. Alternative dispatch strategies (e.g., for distribution system benefits) are discussed later in this section.

A. Winter Peak Day

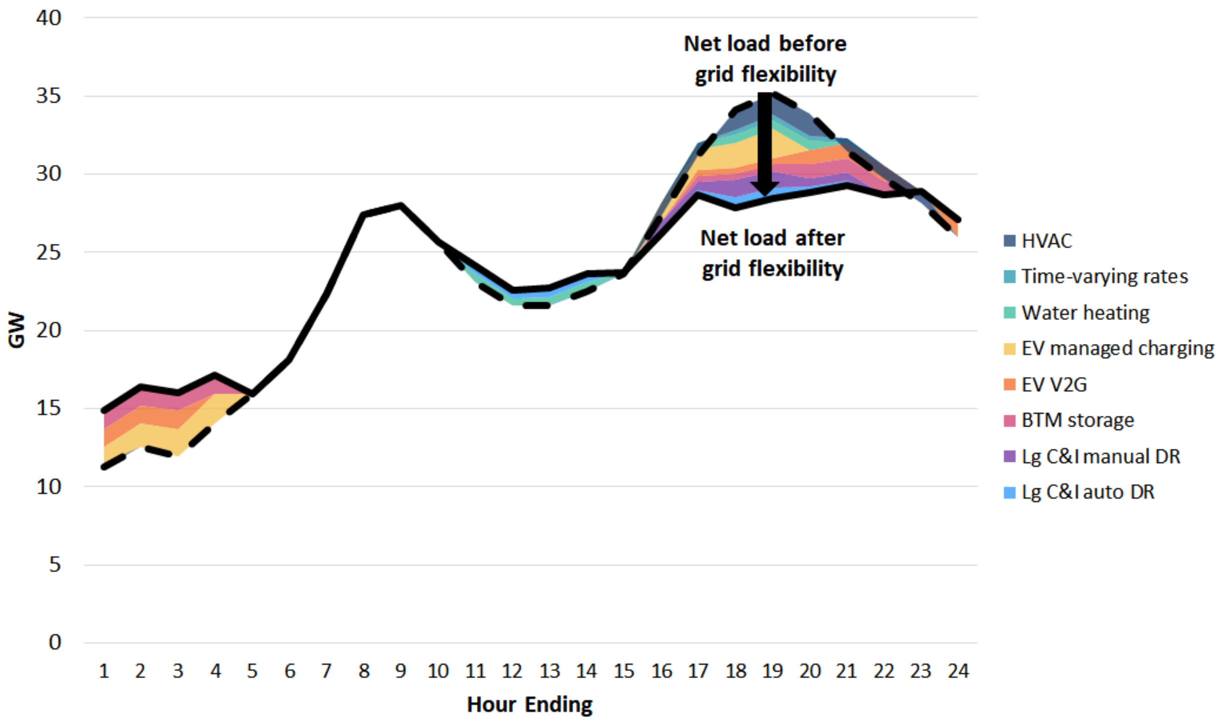
If New York's Climate Leadership & Community Protection Act (CLCPA) electrification goals are met, New York is expected to be a winter peaking system in 2040, with peak net load hours occurring in the evening or early morning. On peak days, all grid flexibility options would be available to reduce system net load. Figure 1 provides an illustration of how the statewide portfolio could be dispatched on a winter peak day.

9 We reported flexibility potential as the average reduction achieved over the three-hour system-wide net peak load window for each season. See Volume I report for additional detail. The three-hr system-wide net peak load window is 6-9 p.m. from May through October and 5-8 p.m. from November through April. These peak windows tend to be the highest risk hours for supply shortfalls and therefore identify the operational need for load flexibility.

10 We illustrate dispatch for the cost-effective portfolio quantified in the Volume I report. The portfolio accounts for program enrollment overlap (e.g., time-varying rate impacts exclude HVAC load reductions if customers are also enrolled in smart thermostat programs). If each program was offered in isolation the individual program impacts could be greater than the components of the portfolio shown in the below figures.

11 We define net load as gross load less distributed solar, utility scale solar, and onshore and offshore wind. The remaining load will need to be served by a combination of grid flexibility, utility scale storage, and other resources.

FIGURE 1: WINTER PEAK DAY GRID FLEXIBILITY DISPATCH ILLUSTRATION (STATEWIDE, 2040)[12]



Portfolio dispatch is concentrated in the period from 3 p.m. through 10 p.m. to reduce daily net peak load from around 35 GW in the afternoon to 29 GW in the late evening hours. This reduction of 6 GW over 7 hours is less than the 8.5 GW potential estimate reported over a single 3-hour window. In this illustration, we assume programs are staggered across more than three hours to achieve load reductions during all hours of the day that would be needed to "flatten" the peak.

We assume that certain programs, like heating control, can only be called for 3-hour events in order to manage the risk of participant inconvenience. Other programs, like battery storage, are shown in the illustration to stagger dispatch to reduce demand throughout the evening peak. Evening load is shifted to overnight and midday hours for programs with end-uses that require charging and pre-heating (e.g., vehicle charging, storage, and water heating programs). This provides the potential benefit of reduced renewables curtailments on certain days or in certain locations, while also serving the shifted load at a lower cost.

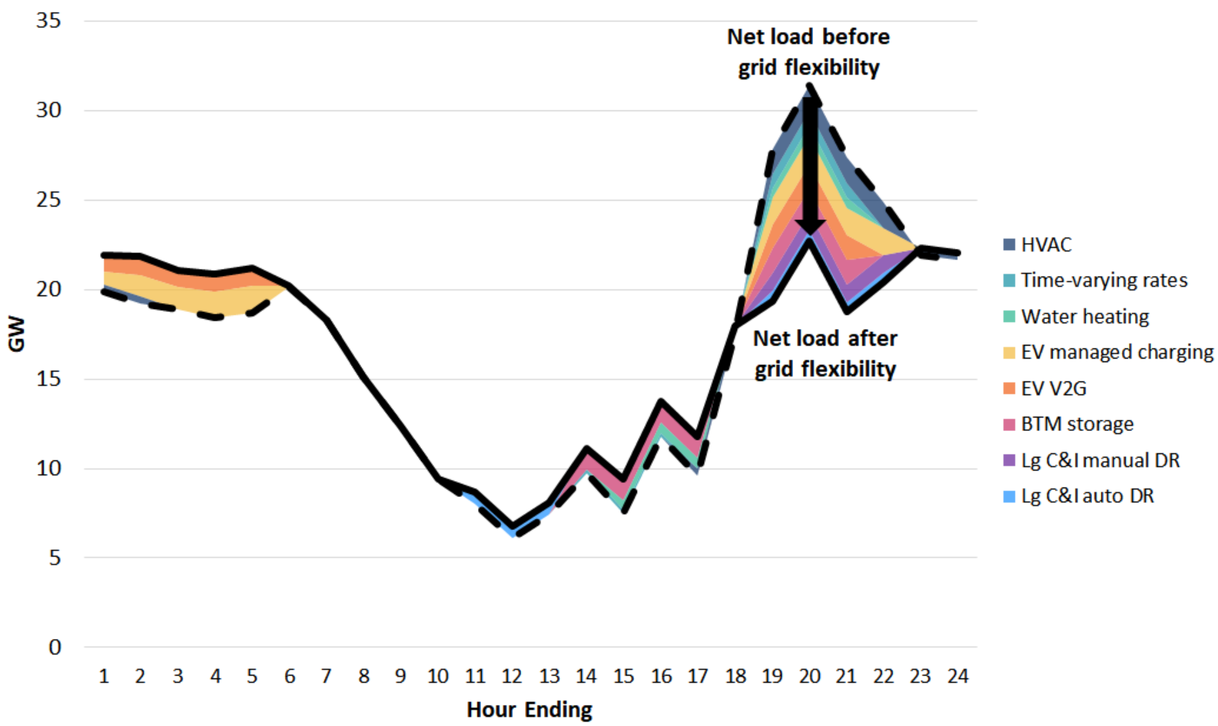
B. Summer Peak Day

Summer days will experience less frequent resource adequacy risk conditions than in the winter by 2040. However, grid flexibility still can provide resource adequacy value through load reductions during heat waves and other peak conditions, as well as reduce energy costs. Grid flexibility measures can

12 Net load is depicted for a single peak day. Hour 1 is continuous with Hour 24 from the prior day and Hour 24 is continuous with Hour 1 in the subsequent day.

reduce summer evening peaks and shift demand into mid-day hours with high solar production. Figure 2 illustrates an example flexibility portfolio dispatch on a summer peak day that reduces net peak demand by 8.5 GW.

FIGURE 2: SUMMER PEAK DAY GRID FLEXIBILITY DISPATCH ILLUSTRATION (STATEWIDE, 2040)[13]



Grid flexibility dispatch is concentrated in the period from 6 pm through 9 pm to reduce the net peak from around 31 GW to 23 GW at 7 pm. Given the significant ramp in net load in the early evening, all programs are simulated as being dispatched at full capacity during the three-hour net peak window rather than staggered over a greater number of hours. This grid flexibility dispatch pattern could reduce the system need for a quick ramp of generation and/or battery storage assets. Average demand reduction during the net peak window (6 pm to 8 pm) is 8.5 GW.

Evening load is shifted to late night and early morning hours for electric vehicle programs, to ensure that morning driving needs are met. Load is shifted to both evening and midday hours for other programs that require charging or pre-heating/pre-cooling.

C. Average Winter and Summer Days

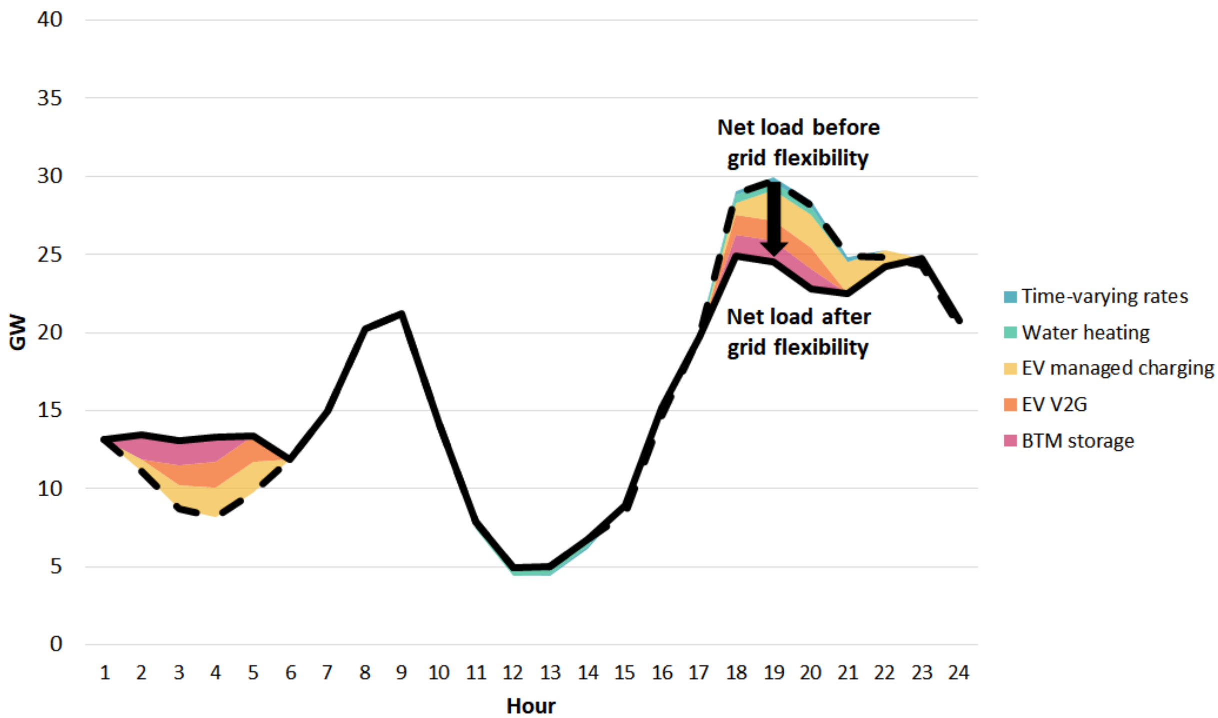
Average load days are less likely to drive the need for system capacity investments (e.g., generation capacity or T&D infrastructure), but dispatching available flexibility measures can still provide system

13 Net load is depicted for a single peak day, based on modeled data from the forthcoming NYSERDA GE Holistic Reliability Study. The variability of midday net load is due to the interaction of modeled statewide gross load and renewable generation.

value by reducing energy costs (e.g., generation operational expenses). On these average load days, only programs without event limitations are assumed to be dispatched, to minimize the potential for customer fatigue and to reserve grid flexibility resources for higher value conditions on other days. EV managed charging, EV V2G, BTM storage, water heating, and time-varying rates are the modeled options assumed to be available to operate on a near-daily basis.

On average winter days, net load is higher during evening and early morning hours, with a significant drop in net load during mid-day hours due to high solar generation relative to modest load. Figure 3 illustrates the load on an average winter day.

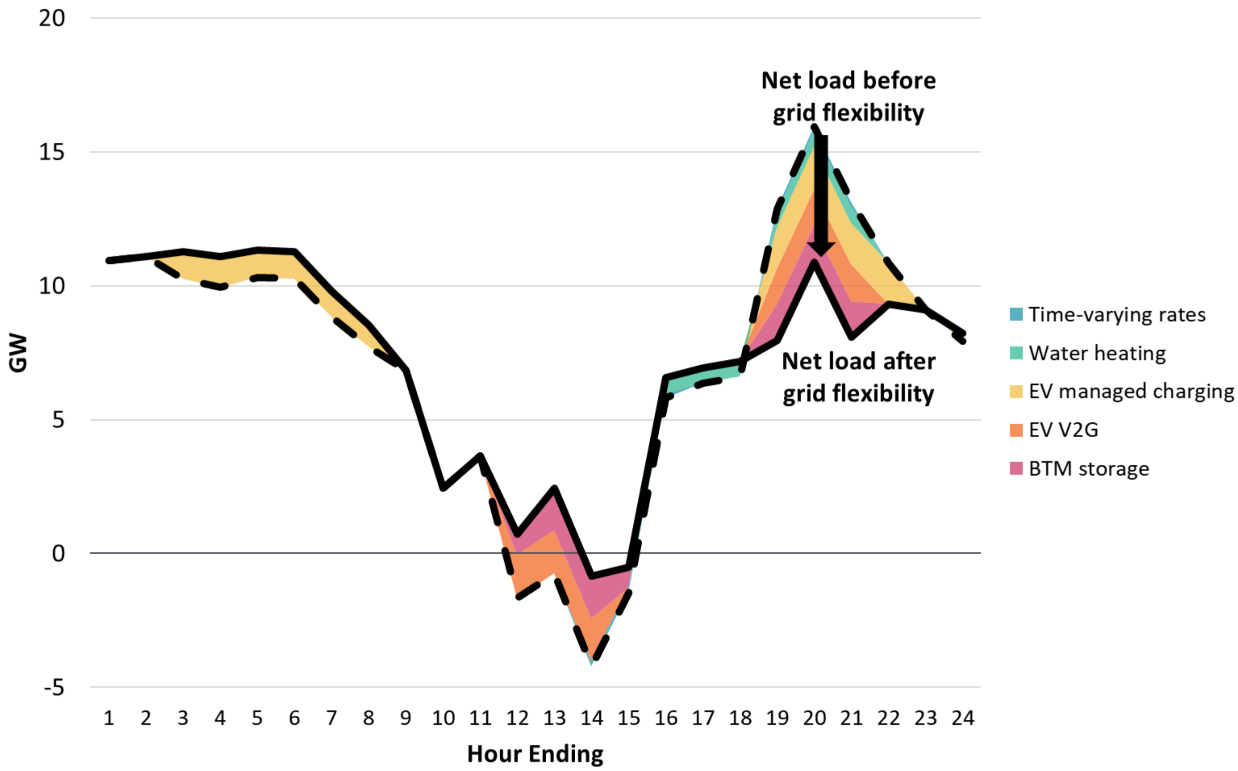
FIGURE 3: WINTER "AVERAGE" DAY GRID FLEXIBILITY DISPATCH ILLUSTRATION (STATEWIDE, 2040)



Simulated grid flexibility dispatch shifts evening charging to overnight hours and ensures that participants' driving needs are met. Water heating load is more flexible from a behavioral standpoint and is shifted to midday hours. This strategy reduces reliance on more expensive generation assets to serve evening peak load.

The same portfolio of frequent load shifting programs is available for dispatch on average summer days. Renewable generation drives net load negative during midday hours, which creates opportunities for BTM storage and EV V2G charging to reduce curtailments. Figure 3 illustrates the load reduction potential on an average summer day at the New York system level in 2040.

FIGURE 4: SUMMER “AVERAGE” DAY GRID FLEXIBILITY DISPATCH ILLUSTRATION (STATEWIDE, 2040)



The net load peak shifts from 7 pm to the very early morning hours, although this shift could be lessened with more EV managed charging during midday hours, depending on the charging needs of the customer. During negative net load hours, the New York system will either curtail surplus renewables or export generation to neighboring systems. Shifting some vehicle charging and BTM storage charging to low-cost or negative net load hours is one of the ways grid flexibility can provide value on non-peak days.

D. Alternative Dispatch Strategies

There are many use cases for grid flexibility beyond the illustrations above. Examples of additional dispatch strategies that can serve system needs include:

- **Reduce utility system peak demand**. Grid flexibility programs can be dispatched to serve utility-specific system peaks, which may occur in different hours or seasons than the statewide system peak. Some utilities, like ConEd, often have local peaks that are not coincident with the statewide peaking conditions due to the diversity and density of Manhattan loads.
- **Reduce distribution system peak demand.** Our modeling in Volume I accounted for the value associated with deploying grid flexibility to reduce demand on substations that were expected to face overload conditions within the study period. With adequate control capabilities and system data, grid flexibility measures can reduce distribution system peaks, which can vary by location. Program dispatch strategies would be local to the distribution system conditions and customers

would be called based on their location. An area for further exploration is the trade-offs involved in utilizing grid flexibility programs to provide both distribution system and bulk system benefits.

- **Reduce gross system peak demand.** While net load conditions will drive resource adequacy risk and system costs associated with procuring and operating generation capacity, grid flexibility programs can also provide value by targeting gross system peak demand. Notably, gross peak loads drive capacity requirements at the ISO and zonal levels. Targeting gross peaks could reduce generation capacity obligations or also potentially reduce peak demand-related transmission system investments, if deployed at sufficient scale and the necessary level of operational dependability.

Optimal dispatch decisions will vary by region based on the pace and level of renewable deployment, electrification, and infrastructure investment. As system conditions evolve, grid flexibility dispatch strategies can adjust to provide the most valuable services for statewide, utility level, or local system needs.

III. Grid Flexibility Potential Sensitivity Analysis

The estimates of grid flexibility potential presented in the Volume I report are driven by a modeling baseline that assumes full achievement of New York's energy policy goals. This definition allows us to assess the role that grid flexibility can play in facilitating the achievement of those goals. The results of that modeling correspondingly confirm that grid flexibility can make significant contributions toward cost-effectively addressing the statewide power system needs in a policy-compliant future scenario.

At the same time, it is important to understand the sensitivity of our study findings to alternative baseline assumptions. As with any forward-looking analysis, there is uncertainty regarding the future state of the New York power system in 2040. Sensitivity analysis provides insight regarding the robustness of the findings to changes in the power system outlook, and also highlights the modeling assumptions that are the most impactful drivers of the study results. This section of the report defines and summarizes the results of the sensitivity analysis.

A. Approach Overview

To conduct the sensitivity analysis, we first identified the modeling input assumptions that we considered to have the most uncertainty and/or to be the most significant drivers of results. For each input assumption, we established a high case, which relies on plausible inputs that would create more favorable grid flexibility conditions (i.e., higher value), and a low case that would result in less favorable grid flexibility conditions (i.e., lower value).

We implemented each sensitivity case as an isolated change to the base case model. In other words, we did not combine the low case for multiple variables to create a new scenario - each was implemented as an individual model run. A benefit of this approach is that it provides insight regarding the relative impact of individual drivers of grid flexibility potential and can therefore help to inform future targeted initiatives to remove barriers to grid flexibility deployment.

Table 1 summarizes the sensitivity cases, with the base case assumptions (i.e., the Volume I report assumptions) provided as a point of reference. Appendix A describes each of the sensitivity inputs in more detail.

TABLE 1: 2040 SENSITIVITY ANALYSIS INPUT SUMMARY

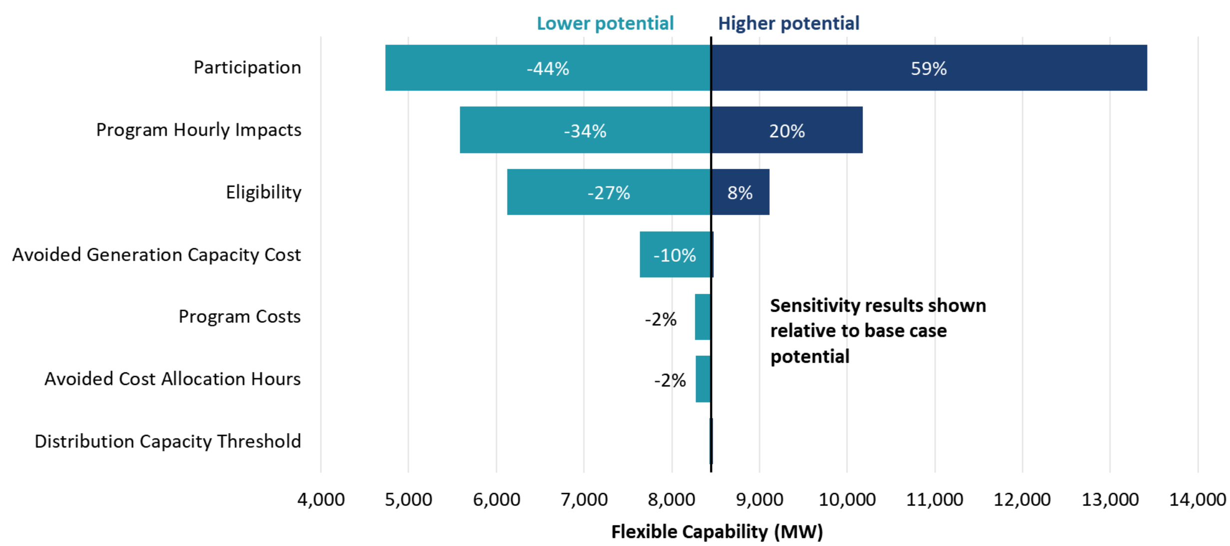
	Base Case	High Case	Low Case
Participation	Based on observed achievable participation in programs in New York, other jurisdictions, and past studies	Higher participation, based on observed participation rates of the strongest performing programs	Lower participation, based on lower performing (though still successful) programs in literature review
Eligibility	Based on CLCPA policy compliant appliance saturation forecasts for 2040	Faster adoption of controllable equipment (e.g., smart thermostats and BTM storage)	5-year state-wide delay of CLCPA decarbonization targets (e.g., heat pumps, heat pump water heating, EVs)
Program Hourly Impacts	Based on observed and simulated impact and operations of similar programs in a variety of jurisdictions, tailored to NY market conditions	Higher per-customer impacts and more frequent events	Lower per-customer impacts and less frequent events
Avoided Generation Capacity Cost	Based on NREL Cambium 2023's mid-case with 100 percent decarbonization by 2035 scenario	50% higher avoided capacity cost due to uncertainty in future resource mix	50% lower avoided capacity cost due to uncertainty in future resource mix
Distribution Capacity Threshold	Substations are upgraded when load reaches 100% of capacity	Substations are upgraded when load reaches 75% of capacity	No distribution value
Avoided Cost Allocation Hours	Avoided capacity cost (Gx, Tx, and Dx) hourly allocation based on system load analysis	Fewer allocation hours, better program dispatch captures more concentrated value (i.e., higher ELCC)	More allocation hours, less concentrated value (i.e., lower ELCC)
Program Costs	Costs informed by existing programs and vendor input	Lower costs to control smart technologies (includes DERMS, OEM, and equipment costs)	Higher costs to control smart technologies (includes DERMS, OEM, and equipment costs)

B. Results

Grid Flexibility Potential

Figure 5 summarizes how 2040 statewide grid flexibility potential changes for each sensitivity case, relative to the base case estimate of 8.5 GW of winter potential. For example, the figure shows that the sensitivity to low program participation would decrease the potential estimate by 44%, resulting in total grid flexibility potential of around 4.8 GW. Alternatively, the sensitivity to high program participation would increase the potential by 59%, to approximately 13.5 GW.

FIGURE 5: SENSITIVITY ANALYSIS RESULTS FOR FLEXBILITY CAPABILITY (STATEWIDE, WINTER 2040)



A general takeaway from the sensitivity analysis is that the potential estimate is not sensitive to all input assumptions. In particular, the potential estimate is insensitive to alternative assumptions about program costs, the allocation of avoided costs across hours, or the opportunity to defer distribution investments (i.e., those cases at the bottom of the figure). These input assumptions have limited impact on the potential estimates, because they directly affect grid flexibility *value* rather than available grid flexibility *capacity*. Most grid flexibility measures are already highly cost-effective by 2040 in the base case and continue to be highly cost effective in the sensitivity cases that consider lower system value. Across these cases, the cost-effective incentive levels remain consistent with – or higher than – the incentives offered in grid flexibility programs that have achieved successful participation rates across the U.S., so no further adjustments to expected enrollment were warranted.

Grid flexibility potential estimates are most sensitive to assumed maximum achievable participation rates. This finding is supported by the observation that participation rates vary widely in demand flexibility programs across the U.S. Customer participation in grid flexibility offerings is affected by a variety of technical, economic, and behavioral barriers; a focus on strategies for increasing customer engagement will be key to realizing grid flexibility potential. Simple, transparent program incentive structures and streamlined enrollment processes are examples of effective strategies to increase program participation. Additional participation barriers and solutions are discussed in more detail in the Volume I and II reports. A recent study by LBNL and Brattle on proven strategies to increase enrollment in virtual power plant programs also provides further detail in this regard.[14]

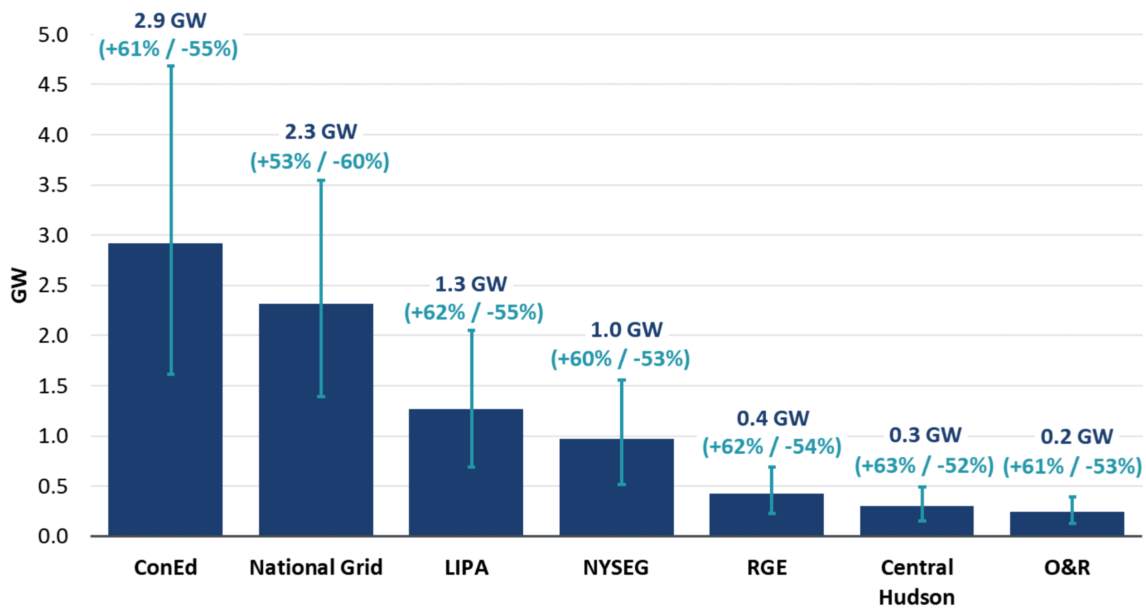
Program hourly impact assumptions are another driver of grid flexibility potential and can swing the results by 20% to 30% in either direction. We model event impacts based on observed per-customer load shifting capabilities relative to consumption baselines, as documented in the Volume II report. Lower estimates account for higher customer-opt-outs and more stringent operational limits on load shifting. Technical advances in automated controls and algorithms that maximize grid flexibility impacts while still maintaining participant comfort will facilitate improvements in this area.

Base case estimates of grid flexibility potential assume customer adoption of controllable electrification-related technologies (e.g., EVs, heat pumps) is driven by achievement of CLCPA climate policies. The high eligibility sensitivity case assumes CLCPA policy compliance with faster adoption of controllable equipment (smart thermostats and BTM storage), increasing the number of customers eligible to enroll in grid flexibility. If technology adoption is slower than envisioned by the CLCPA goals, fewer customers will be eligible to participate in grid flexibility programs by 2040. The lower-case result illustrates the potential impact of delayed achievement of the policy goals. This results in around 25% less grid flexibility potential due to a smaller pool of eligible customers.

The impact of each explored sensitivity case will vary by individual program and utility. Figure 6 shows the potential estimates across sensitivity cases for each utility relative to the base case. The highest and lowest results are driven by alternative participation assumptions that result in a change of around +/-50% relative to the base case potential estimate for each utility.

[14] Hledik, Ryan, Akhilesh Ramakrishnan, Serena Patel, and Andy Satchwell, "Distributed Energy, Utility Scale: 30 Proven Strategies to Increase VPP Enrollment," prepared for U.S. DOE, December 2024.

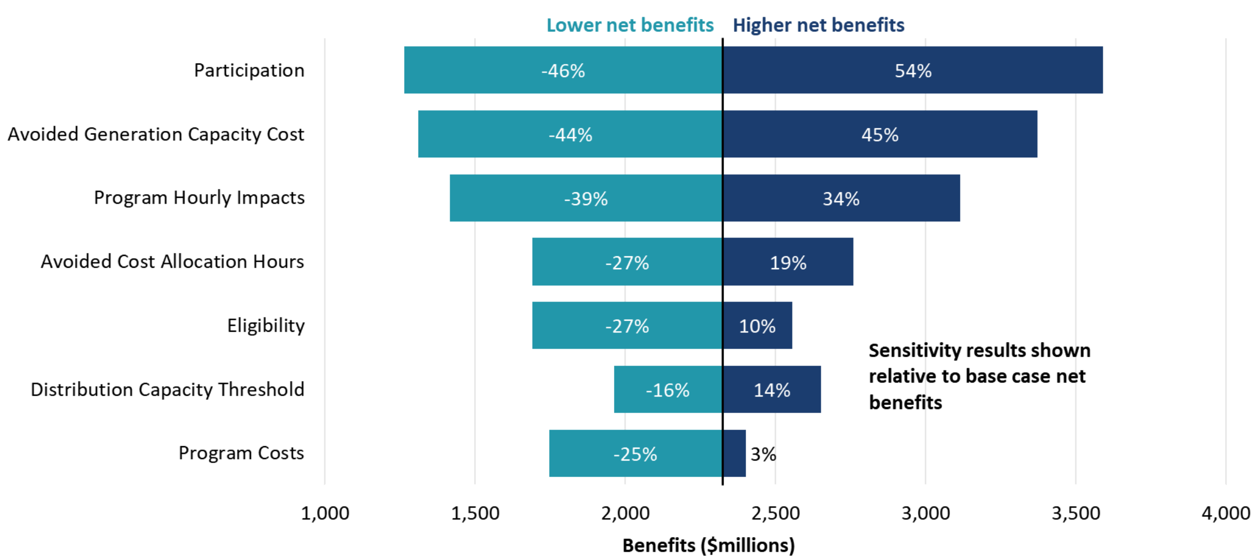
FIGURE 6: SENSITIVITY ANALYSIS RESULTS FOR FLEXBILITY CAPABILITY (BY UTILITY, WINTER 2040)



Grid Flexibility Value

Figure 7 illustrates how the net benefit to consumers of each sensitivity case changes relative to the base case value. For the sensitivity analysis, we characterize net benefits as the financial benefit to both grid flexibility participants and non-participating ratepayers. Net benefits are calculated as the total avoided costs provided by grid flexibility minus program implementation costs (i.e., DERMS, marketing, administrative costs).

FIGURE 7: SENSITIVITY RESULTS FOR NET BENEFITS (STATEWIDE, 2040)



Net benefits, like grid flexibility potential, are most sensitive to participation assumptions. More customer participation increases the energy, generation capacity, and T&D value provided by grid flexibility programs. Cases that evaluate program impacts and eligibility also demonstrate comparable sensitivity to higher or lower input assumptions. Higher per-participant impacts (driven by customer behavior or advances in automated controls), and increased eligibility (driven by faster customer technology adoption), can avoid more system operational costs or investments. The inverse also applies.

Net benefits are also sensitive to the future cost of generation capacity. As discussed in Volume I, higher cost resources will be needed to support a fully decarbonized power system, and grid flexibility can play an important role in offsetting those costs. However, the costs of those future generation technologies remain uncertain. We developed our 2040 capacity value sensitivity assumptions, ranging from $111/kW-yr to $333/kW-yr statewide (in 2024 dollars), from a review of public forecasts. See Appendix A for further details.

The avoided cost allocation hours sensitivity case reflects the uncertainty in the availability needed from grid flexibility in order to avoid generation capacity, transmission, or distribution investment. In the high potential case, we assume the power system requires fewer, more targeted dispatch hours, which leads to higher system net benefits. In the low potential case, we assume grid flexibility needs to be dispatched in a higher number of hours to defer capacity-related investments, and fewer investments will be deferrable, leading to lower grid flexibility value.

The distribution capacity threshold sensitivity cases test uncertainty in the scale of future distribution system upgrades that could be deferred through grid flexibility. Utilities across the U.S. and in New York follow different planning standards for allowable maximum loading of different types of distribution assets. Typical loading limits for substations range from 75% to 100% and can be as high as 130%. In a high load growth paradigm, some utilities may revise their criteria downward in order to begin planning for grid upgrades earlier, leaving more buffer for new customers to be connected without delays[15]. To reflect this range of planning practices, we assume a loading limit of 100% in the base case and 75% in the high potential case, thereby expanding opportunities for grid flexibility programs to deliver distribution value. Utilizing grid flexibility programs for targeted distribution deferral projects requires coordinated, timely deployment and operation of these resources and integration into distribution system planning processes. There has been limited experience with this use case so far, and there is uncertainty around scaling of pilot programs, coordination of distribution and bulk system use cases, and the development of communication and control capabilities needed to utilize flexibility resources for distribution deferral. To reflect this uncertainty in the Low Potential Scenario, we show the impact on grid flexibility potential if grid flexibility programs cannot provide any distribution system value.

We also test the sensitivity of net benefits to program cost assumptions, specifically the costs required to control customer end-use devices. The rate at which these costs change will depend on market competition and the pace at which economies of scale and scope are reached, among other factors. Based on the assumptions in our modeling, a slower rate of control technology cost decline through 2040 could reduce net benefits by 25% relative to base case assumptions.

---

15 Examples of utilities revising their planning criteria downward include Xcel Energy and Eversource Energy

IV. Additional Grid Flexibility Options

New York's grid flexibility could be provided from a range of technologies and behavioral options. Several of these options were outside the scope of our quantitative analysis of achievable grid flexibility potential[16] but could play an important role in delivering future grid flexibility regardless. Those additional grid flexibility options include medium and heavy-duty vehicle managed and bidirectional charging, front-of-the-meter distributed energy storage, energy efficiency, customer load management systems, thermal energy networks and thermal energy storage, and large new loads with microgrids. In this section of the report, we describe each grid flexibility option, the future role that each option could play in addressing the New York power system's flexibility needs, and unique barriers limiting their deployment.

A. Medium and Heavy-Duty Vehicle Managed and Bidirectional Charging

Managed charging for Medium and Heavy-Duty Vehicles (MHDVs) refers to controlling the charging of electric trucks, buses, and other large vehicles to provide grid services and reduce costs.[17]

Charging multiple MHDVs simultaneously could strain the grid and require distribution system upgrades to support higher load, if not properly managed. Due to their larger batteries, these larger vehicles also require significant amounts of electricity.

However, flexible operational schedules of certain types of MHDVs may make them particularly favorable for managed charging. For example, electric buses that remain in bus depots for long periods of time are good candidates for managed charging, since their charging load can be shifted according to the grid's needs while they remain plugged in. In general, vehicles with predictable schedules and long dwell times are more amenable to managed charging. Fleet operators are more likely to adopt managed charging if they can identify opportunities to reduce energy costs or connect to the grid more quickly, while accommodating their vehicle operation schedules.

Managed charging encompasses multiple ways of controlling the charging load. As in the case of light duty vehicles, managed charging for MHDVs typically provides grid flexibility by shifting charging load to an off-peak time period, where the demand on the grid is lower and the underlying costs to serve customers and/or grid greenhouse gas emissions are lower. Our assessment of future New York power

[16] Case 24-E-0165, Grid of the Future Proceeding, Grid Flexibility Potential Study Phase 1 Final Report (filed January 31, 2025), p. 36.

[17] Vehicle types in the MHDV segment include school buses, transit buses, other public transit vehicles, delivery vans, refuse trucks, agricultural vehicles such as tractors, heavy duty equipment such as excavators, maritime vehicles such as boats and port equipment.

system conditions also identified the middle of the day as an attractive time for charging (if it can be accommodated by the MHDV's charging needs) due to the potential for curtailed solar output.

Load shifting can be achieved through "passive managed charging" (or behavioral managed charging), where time-of-use rates or other financial incentives encourage customers to charge during off-peak times of day with cheaper rates. Alternatively, "active managed charging" programs enable load shifting by allowing the utility or aggregator to control the charging load through the charger or the vehicle's onboard telematics. Program participants receive compensation in return.

Examples of both passive and active managed charging programs for MHDVs exist in New York. For example, Con Edison encourages EV fleet operators to opt for time-of-use rate options (SC-9 Rate II and III) if they have flexible demand[18] and provides a calculator to help EV fleet customers choose between conventional and time-of-use rate options.[19] The utility also launched an active managed charging program for commercial EV operators which provides incentives for charging overnight and avoiding charging when the local demand for power is high in the EV operator's neighborhood.[20]

Bidirectional charging, where an EV can export electricity to a building (Vehicle-to-Building), or to another load such as an appliance or another EV (Vehicle-to-Load, Vehicle-to-Vehicle), or to the grid (Vehicle-to-Grid) is another option for MHDVs to offer grid flexibility.[21] Bidirectional charging requires a specialized bidirectional charger and energy management software to communicate between devices. In the case of Vehicle-to-Grid (V2G), an interconnection agreement with a local utility and communication between the vehicle and the utility/aggregator is also required.

V2G is a promising option to enable MHDVs to provide grid flexibility; however, V2G is still in the early stages of implementation and there is limited real-world data on the V2G experience for MHDVs, partially due to the nascent state of electrification in this vehicle segment. V2G has been an area of focus especially for electric school buses and several utilities have implemented V2G school bus pilots in New York, Massachusetts, Vermont, Maine, and California.[22] Con Edison has demonstrated the potential for electric school buses to provide grid support through a V2G pilot in 2018-2021 timeframe.[23] The pilot led to valuable lessons regarding hardware replacement, software integration, and operator training. Considering that New York requires all new school bus purchases be zero-emissions by 2027 and all

---

[18] Con Edison Electric Delivery Rate for Your Charging Station, Accessed Feb 19, 2025.

[19] Con Edison Charging Calculator, Accessed Feb 19, 2025.

[20] Con Edison Launches Managed Charging Program | Con Edison, Accessed Feb 19, 2025.

[21] Smart Electric Power Alliance, State of Bidirectional Charging in 2023, September 2023. Vehicle-to-Home (V2H) can provide supplemental power to reduce the customer's peak energy use or backup power in the case of grid outages. Vehicle-to-Load (V2L) applications provide resiliency in the case of grid outages as well as off-grid electricity use. Vehicle-to-Grid (V2G) can support the grid by providing capacity, energy arbitrage, voltage support, and frequency regulation, and other ancillary services. Vehicles can be aggregated to form a virtual power plant (VPP).

[22] Efficiency Maine, Vehicle-to-Grid Pilot Assessment, Staff Report of the Efficiency Maine Trust, Submitted to the Joint Standing Committee on Energy, Utilities and Technology of the Maine State Legislature, January 15, 2024.

[23] Con Edison, Findings from E-School Bus Project, April 12, 2022; Con Edison, REV Demonstration Project: Electric School Bus V2G Q1 2022 Quarterly Progress Report, May 2, 2022.

school buses on the road be zero-emissions by 2035, there is growing potential for school bus managed and bidirectional charging.[24]

New York's potential for implementing managed charging for other types of MHDVs will increase as well, given the state's mandates and programs encouraging the adoption of electric MHDVs. For instance, New York is one of the signatory states to a memorandum of understanding to support the deployment of zero-emission MHDVs.[25] Beginning with model year 2025, manufacturers will be required to sell zero-emission trucks as an increasing percentage of their annual sales for Class 2b through Class 8 vehicles in New York.[26] The Joint Utilities are offering a make-ready incentive pilot program to provide incentives to reduce the cost of EV charging infrastructure for MHDVs.[27] The New York City Clean Trucks Program[28] and the New York Truck Voucher Incentive Program[29] offer financial incentives for replacement of conventional vehicles with electric ones.

There are various regulatory and technical barriers in MHDV managed charging applications. Since MHDV electrification is in the early stages, there is little evidence on which types of fleets have the flexibility to do managed charging. There are many challenges that need to be addressed to enable electrification, and adding managed charging capabilities is a long-term proposition.

There are barriers specific to V2G as well. For example, the interconnection processes required for V2G may introduce delays and additional costs on customers. For example, an electric school bus V2G pilot in Maine encountered a barrier in the state's grid interconnection rules, which grouped V2G projects with every other generation project without considering the plausible charge-discharge schedules for a V2G program.[30] Regulations will need to be revised to consider operational characteristics and support the growth of V2G applications.

A technical challenge, especially for bidirectional charging, is the reliance of many different types of software and hardware. Enhancing interoperability and standardizing products will facilitate communication between different devices and prevent dependence on proprietary technologies. Electric school bus pilots across the country also experienced various software, hardware, and operational challenges. As lessons learned from pilots are shared across jurisdictions and more of these

[24] State of New York, Division of the Budget. Governor Hochul Announces FY 2023 Investments in Clean Energy Infrastructure, Climate Resiliency and Preservation, April 9, 2022. To support this transition, New York School Bus Incentive Program provides vouchers for electric and hydrogen fuel cell school bus adoption: NYSERDA, NY School Bus Incentive Program Overview, Accessed Feb 21, 2025.

[25] ZEV Task Force, Multi-State Medium- and Heavy-Duty Task Force Zero-Emission Vehicle Action Plan, July 2022.

[26] Alternative Fuels Data Center: Medium- and Heavy-Duty Zero Emission Vehicle (ZEV) Requirement, Accessed Feb 21, 2025.

[27] New York Electric Vehicle Infrastructure Medium- and Heavy-Duty Vehicle Make-Ready Pilot Program. Amended Implementation Plan Submitted by: Central Hudson Gas & Electric Corporation Consolidated Edison Company of New York, Inc. Niagara Mohawk Power Corporation d/b/a National Grid New York State Electric & Gas Corporation Rochester Gas & Electric Corporation Orange & Rockland Utilities, Inc, Case 18-E-0138, Feb 6, 2024.

[28] NYC Clean Trucks Program, Accessed Feb 21, 2025.

[29] NYSERDA, New York Truck Voucher Incentive Program (NYTVIP), Accessed Feb 21, 2025.

[30] Efficiency Maine, Vehicle-to-Grid Pilot Assessment, Staff Report of the Efficiency Maine Trust, Submitted to the Joint Standing Committee on Energy, Utilities and Technology of the Maine State Legislature, January 15, 2024.

challenges are addressed or eliminated beforehand, implementation is expected to become more streamlined. Pilots involving other types of MHDVs would be valuable for providing lessons on the potential for managed charging for a wider suite of MHDVs going forward. Establishing comprehensive customer compensation mechanisms for managed charging will help attract MHDV fleets, especially if EV charging accounts for a large portion of their energy bills.

B. Front-of-the-Meter Distributed Energy Storage

For the purposes of this report, we define front-of-the-meter (FTM) distributed energy storage systems as being located on the utility side of the meter but connected to the distribution system. While a behind-the-meter (BTM) system produces and delivers power directly for on-site use, bypassing the meter, an FTM system (such as a commercial or utility-scale generation and storage system) supplies power to the distribution grid. FTM distributed energy storage systems may be located on the premises of an end-use electricity customer. By interconnecting to the distribution grid in front of the meter, an FTM energy storage system can provide energy to the grid or serve certain local loads while avoiding the use of the transmission grid.

FTM distributed storage systems can provide grid flexibility by storing excess energy during low value periods and discharging when the value of that output is high. Since they can dispatch quickly during periods of high demand, they can provide resource adequacy value. FTM batteries can also enable load balancing, reduce transmission losses, and regulate voltage.

FTM distributed storage can be used as part of a microgrid and serve multiple utility customers. For example, SDG&E in California has been installing FTM batteries as part of its microgrid portfolio.[31] These projects enable the California Independent System Operator (CAISO) to dispatch energy from the batteries to help balance supply and demand. An FTM distributed storage system serving local loads can also enhance resiliency by providing power during broader grid outages if configured appropriately.

New York has set a goal of installing 6 GW of energy storage by 2030, 1.5 GW of which will be sourced from new retail energy storage projects.[32] FTM distributed storage can play a role in meeting this goal. The storage deployment policy established by the New York PSC recognized the potential system benefits of FTM retail storage and directed NYSERDA to develop a retail storage program which offers incentives for both FTM and BTM systems.[33] The PSC recently approved NYSERDA's implementation plan with modifications.[34]

FTM distributed storage resources already contribute to New York's electricity system. These resources can participate in New York Independent System Operator (NYISO)'s wholesale energy, ancillary services, and capacity market products either on an individual project basis or through an approved

---

31 Battery Energy Storage Systems (BESS) and Microgrids | San Diego Gas & Electric

32 State of New York Public Service Commission, Order Establishing Updated Energy Storage Goal and Deployment Policy, Case 18-E-0130 - In the Matter of Energy Storage Deployment Program, June 20, 2024.

33 NYSERDA, Retail Storage Incentives, Accessed February 28, 2025.

34 State of New York Public Service Commission, Order Approving Implementation Plan with Modifications, Case 18-E-0130 - In the Matter of Energy Storage Deployment Program, February 13, 2025.

"distributed energy resource (DER) aggregator," which combines multiple DERs to build a resource of sufficient size.[35] Resources can then earn revenues by providing energy and capacity during high demand periods and helping balance grid fluctuations.[36]

New York's Value of Distributed Energy Resources (VDER) program provides an alternative compensation mechanism for FTM distributed storage as well as for other DERs. The VDER program compensates resources for distribution grid value based on how much they reduce load in high congestion periods and locations, thereby reducing the need for future grid upgrades. FTM distributed storage with less than 5 MW capacity can participate in the VDER program. Since one of the determinants of the VDER "value stack" is capacity value, which is estimated based on the exported energy during NYISO's peak hour of the year, storage systems can earn more credits by discharging during the annual peak.

Several FTM distributed storage systems have been installed in New York. For example, six FTM standalone energy storage systems were installed in Staten Island, New York, with over 110 MWh of storage capacity. The projects participate in the VDER program using a smart energy software to optimize revenue streams from multiple incentives.[37] Three new FTM storage systems are planned in Westchester County, adding 13.5 MW/55.7 MWh of capacity. These projects plan to participate in the VDER program as well as the NYISO wholesale energy and capacity market.[38] Going forward, locations with more grid congestion such as New York City and Long Island can particularly benefit from FTM storage assets that can alleviate grid congestion.

While New York is already making progress towards its goal of increasing its FTM distributed storage deployment through new installations and incentive programs, there is room for further improvements. In particular, stakeholders point to significant areas of improvement for FTM distributed storage participation in the VDER program. Recommended modifications along these lines include making periodic revisions to the projected charge/discharge profiles of projects to account for changes in the electricity system, updating the capacity component of VDER to make this revenue stream more predictable, and increasing the eligible project size limits.[39]

Another barrier for FTM distributed storage deployment is a complex compensation structure. The compensation mechanisms currently available to distributed storage systems incentivize discharging during a limited number of summer system peak hours and fail to incentivize discharging outside these hours. One proposed solution is developing a new "bidirectional service classification" tariff. Among various proposed solutions to address the challenges faced by distributed storage, this tariff would

---

35 NYISO, NYISO Implements Nation's First Market Empowering Distributed Energy Resources, April 18, 2024.

36 NYISO, Comments in Response to e New York State Public Service Commission's Notice Announcing Webinars and Soliciting Comments, Case No. 18-E-0130 - In the Matter of Energy Storage Deployment Program, March 20, 2023.

37 Renewable Energy World, Partners advance FTM energy storage project in New York, January 25, 2022.

38 Enel North America, Enel breaks ground on three front-of-the-meter battery storage systems in Westchester County, New York, December 14, 2023.

39 NineDot Energy, New-York-Energy-Storage-Roadmap-Comments, Case 18-E-0130 – In the Matter of Energy Storage Deployment Program, March 20, 2023.

incorporate time-differentiated, network-variant, and market-based pricing signals for both charging and discharging.[40]

Another area limiting deployment of FTM distributed storage projects is uncertainty in costs and time involved in the interconnection process.[41] Streamlining and standardizing the interconnection requirements can help fast-track the interconnection process. For instance, the U.S. Department of Energy's Distributed Energy Resource Interconnection Roadmap[42] recommends standardizing the technical data that developers of large DER systems must provide on interconnection applications to facilitate interconnection studies, since these larger projects may require more time- and cost-intensive interconnection studies.

C. Energy Efficiency

While the energy savings from energy efficiency upgrades are static (i.e., non-dispatchable), energy efficiency could provide grid flexibility in the broad sense of the term by reducing electricity demand during the times when it is most valuable to the system, and in locations where it has the most value. Certain technologies can be particularly effective in providing load reductions at times and locations when they are most needed. For example, geothermal heat pumps provide heat in the coldest hours of the year with lower electricity consumption relative to air source heat pumps. Geothermal heat pumps have a higher energy conversion efficiency that is not affected by ambient temperature, unlike air source heat pumps, resulting in lower energy usage in cold temperatures. This concentration of demand reductions in the coldest hours of the year will be valuable in a future winter-peaking electric system. Similarly, any energy efficiency measure that can deliver load reductions concentrated during system peaks can offer greater grid benefits per-kWh of energy savings relative to other measures that offer less targeted demand reductions.

Among U.S. states, New York is a leader in energy efficiency and consistently ranks near the top of ACEEE's state energy efficiency scorecard.[43] Appliance standards, building codes, and utility programs all have contributed to New York's achievements in this area. For example, New York enacted the Advanced Building Codes, Appliance and Equipment Efficiency Standards Act which authorized NYSERDA to adopt efficiency standards for a wide range of products.[44,45] New York is one of the states that offers equity-focused programs for building and transportation electrification. The state also provides

---

40 NineDot Energy, Designing a Bidirectional Electric Rate to Power New York's Grid of the Future, March 2024.

41 See an example FTM energy storage interconnection case study from California: Clean Coalition, Valencia Gardens Energy Storage (VGES) Project, Front-of-Meter (FOM) Energy Storage Interconnection Case Study, Prepared for California Energy Commission, May 2021, Accessed Feb 23, 2025.

42 U.S. Department of Energy, Office of Energy Efficiency & Renewable Energy, Distributed Energy Resource Interconnection Roadmap Transforming Interconnection by 2035 Interconnection Innovation e-Xchange (i2x), January 16, 2025.

43 ACEEE, The State Energy Efficiency Scorecard, December 2022.

44 NY State Senate Bill 2021-S9405, Advanced Building Codes, Appliance and Equipment Efficiency Standards Act of 2022, May 24, 2022.

45 NYSERDA, New York State Appliance and Equipment Efficiency Standards, Accessed March 14, 2025.

innovative financing mechanisms to leverage private capital and lower the up-front costs of energy efficiency measures.

New York City has also enacted laws to enable the deployment of energy efficient infrastructure.[46] According to New York City's Local Law 97,[47] most buildings over 25,000 square feet are required to meet new energy efficiency and greenhouse gas emissions limits, with stricter limits coming into effect in 2030. For example, the 345 Hudson Street building, which is more than 90 years old, is taking advantage of tenant turnover as an opportunity to upgrade the building's infrastructure with cost-saving, energy-efficient technologies, such as heat pumps, heat recovery and ventilation systems, and connection to adjacent buildings to share waste heat or cooling.[48]

New York utilities and NYSERDA have been implementing energy efficiency programs and helping the state achieve its energy efficiency goals. As part of the state's Reforming the Energy Vision (REV),[49] the NY PSC directed the utilities to file energy efficiency plans and propose annual budgets and targets on a three-year cycle for review and approval. In 2018, the New Efficiency: New York (NE:NY) whitepaper issued by NYSERDA established energy efficiency targets and presented actions to achieve the targets.[50] New York set a statewide 2025 target of 185 TBtu of end-use savings across fuels, including a sub-target to reduce electricity sales by investor-owned utilities by 3% per year by 2025.[51] NYSERDA's Clean Energy Fund has provided funding for energy efficiency research and development across all fuels, emphasizing reducing the costs of retrofits and new constructions and supporting a wide range of innovations such as soft cost reduction and new business models.

Energy efficiency has also been part of the bundle of measures that have been used for non-wires alternatives (NWAs) in New York. NWAs utilize distributed energy resources (DERs) to defer or avoid traditional electric infrastructure investments such as replacing a transformer or upgrading circuits. Typically, NWA projects are sourced via existing customer programs, or New York utilities issue requests for proposals (RFPs) and conduct competitive solicitations to evaluate the bidding proposals. Projects that meet the identified grid needs at reasonable costs and help support the CLCPA goals are selected and implemented. Utilities earn a percentage of the savings achieved by an NWA project and share the savings with customers under a "share-the-savings" structure.[52]

An example of an NWA project that emphasizes energy efficiency with grid flexibility benefits is a recent RFP issued by Con Edison. As part of its NWA portfolio, Con Edison is currently seeking energy efficiency solutions to provide load relief to residential and multifamily customers within the Jamaica substation

---

46 World Economic Forum, Could New York City become the beacon of energy efficiency?, September 26, 2023.

47 New York City Buildings, LL97 Greenhouse Gas Emissions Reduction, Accessed March 10, 2025.

48 NYSERDA, Hudson Square Properties, Accessed March 10, 2025.

49 New York State Department of Public Service, Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Accessed March 10, 2025. *See* Order Adopting Regulatory Policy Framework and Implementation Plan, February 26, 2015.

50 NYSERDA, New Efficiency: New York, April 2018.

51 New York State Department of Public Service, Case 18-M-0084 – Order Authorizing Utility Energy Efficiency and Building Electrification Portfolios Through 2025, January 16, 2020.

52 R. Gold, G. Wilson, Climate-Forward Efficiency Performance Incentives: Rewarding What Matters, ACEEE Summer Study on Energy Efficiency in Buildings, 2022.

territory.[53] The utility is particularly looking for solutions that can provide coincident peak load relief in the summer period and eliminate the need to replace the substation (i.e., the traditional utility project). Technologies of interest include lighting, HVAC, and building envelope upgrades as well as other solutions.

New York's energy efficiency programs are continually being evaluated and revised to meet the state's needs with the goal of focusing ratepayer funding on the most effective measures. The most recent order from the Public Service Commission reoriented the state's energy efficiency portfolio towards programs that are categorized as "strategic" such as building electrification, envelope work, and more complex offerings like controls that can shift how energy is used within buildings, as opposed to low-cost and short-lived measures.[54] A consequence of this transition is that retrofits and electrification will be prioritized for ratepayer funding over other energy efficiency measures such as lighting or behavioral energy efficiency.

A barrier for energy efficiency measures aimed at reducing peak load is insufficient recognition and compensation for the benefits they provide in lowering peak demand. Current energy efficiency programs set targets and evaluate performance of programs based on their "annual energy savings", i.e., annual reduction in MWh of electricity sales by utilities. As a result, the time-varying value of load reductions is not fully considered in the design of programs and their incentive levels.[55]

Potential solutions to updating the performance metrics are being discussed by stakeholders in the NE:NY proceedings.[56] Stakeholders are discussing whether the annual sales reduction metric remains appropriate to drive and assess performance across different types of energy efficiency and electrification initiatives. Utilities proposed shifting from an annual energy savings measure to a lifetime energy savings measure to better reflect and enable the evolution of the NE:NY portfolios towards longer-lived, deeper efficiency measures. Other stakeholders endorsed the use of an alternative single metric, i.e., the Total System Benefits (TSB) metric developed by the Natural Resources Defense Council and adopted in 2021 by the California Public Utilities Commission, as a unifying way to aggregate all electric system benefits and environmental externalities across different resources including efficiency, electrification, and demand response. The TSB incentivizes the California program administrators to target energy conservation in capacity shortfall hours because those hours have the highest utility avoided costs. Energy saved in these hours provides much greater benefit than in other hours, thus focusing effort toward the most beneficial conservation measures.[57]

---

[53] Con Edison, Request for Proposals, Non-Wires Solutions to Provide Customer-Sited Summer Peak Coincident Electric Demand Reduction: Residential, Small Multifamily, and NYCHA Multifamily Market Segments Supplement to the Jamaica Substation Project, Issued January 10, 2025. Accessed March 11, 2025.

[54] New York State Department of Public Service, Case 18-M-0084 – Order Directing Energy Efficiency and Building Electrification Proposals Order, July 20, 2023.

[55] Alliance for Clean Energy New York, Comments on Case 24-E-0165 – Proceeding on Motion of the Commission Regarding the Grid of the Future, November 13, 2024.

[56] New York State Department of Public Service, Case 18-M-0084 – Order Directing Energy Efficiency and Building Electrification Proposals Order, July 20, 2023.

[57] M. Chhabra, One metric to rule them all: A common metric to comprehensively value all distributed energy resources, *The Electricity Journal*, 35:107192, 2022.

Another barrier to maximizing the grid benefits of energy efficiency programs is the fragmentation of different measures into separate programs, each with its own distinct goals. When a combination of measures including efficiency and electrification is pursued at the same location, the resulting grid benefits can be amplified. For example, implementing building envelope upgrades before adopting heat pumps can reduce the capacity of the heat pumps necessary to electrify a building and therefore partially avoid the increase in peak demand. One potential solution can be providing electric utilities with annual envelope load reduction goals tied to their rate of installed heat pump capacity.[58] Conducting both envelope upgrades and heat pump installations may increase the upfront costs discouraging some customers; however, this solution may pay off in the long run in the form of bill savings for the customer and grid benefits for the system.

D. Customer Load Management Systems

Several types of devices on the market today enable advanced measurement, monitoring, energy management, and control of a customer's electricity load. For the purposes of this report, when used together to control a customer's electricity load, we refer to this suite of technologies as a customer load management system (CLMS). A CLMS can have many different control architectures using some combination of advanced meters ("AMI 2.0"), meter socket adapters (MSAs), smart panels, home energy management systems, smart appliances, and smart inverters. A brief description of each technology is provided below.

- **AMI 2.0**[59]**:** The next generation of utility meters that come with edge computing and software capabilities to enable more visibility into energy end uses, and communication between the utility and customer devices.
- **Meter socket adapters**: An adapter connected between the meter and the electrical panel. MSAs connect specific loads (or DERs) to the meter, bypassing the panel. They can manage the customer's total demand by disconnecting the MSA-connected load when the whole premise load exceeds a predetermined limit.
- **Smart panels**[60]: Electrical panels that are capable of circuit-level monitoring and control. They can disconnect specific circuits within a home when needed to manage the home's total demand, and potentially act as a gateway to metering and/or controlling devices within the home.
- **Energy management systems**: Software that interfaces with customer appliances to manage their energy usage.

58 Performance Systems Development, Case 18-M-0084, Comments of Performance Systems Development in the Matter of a Comprehensive Energy Efficiency Initiative, 2023.

59 AMI 2.0: Planning for Next-Gen Advanced Metering Infrastructure | Deloitte US

60 2023 BTO Peer Review – NREL – Smart Electrical Panel-Based Home Energy Management System (HEMS)

- **Smart appliances**: Various appliances such as EV chargers, induction stoves, washers, dryers, etc. now come with energy monitoring and communication capabilities that can enable demand management.
- **Smart inverters**: Smart inverters are used to connect DERs to the grid and are generally capable of providing additional grid service and integration functions[61].

Today, the most common use case for CLMS in New York and across the U.S. is for avoidance of electrical panel or utility service upgrades when adding new appliances or DERs to homes with smaller connections[62]. Panel or utility service upgrades can be expensive and involve lengthy wait times for project execution. Therefore, a system that can reliably curtail appliances as needed to limit the home's load to the available panel/service capacity can offer customers significant savings. Another use case for some of the components of CLMS is for customers to be able to monitor their energy usage. This can help inform their usage patterns and potentially enable utility bill savings through behavioral changes.

With appropriate policy, planning, and compensations mechanisms in place, CLMS have the potential to be deployed and utilized for a third use case – grid flexibility. Being able to reliably limit a customer's demand can provide significant value beyond avoided panel or service upgrades. Limiting customers' peak demand also indirectly reduces the need to upgrade upstream portions of the grid, depending on how coincident the curtailed loads may have been with distribution and transmission grid peaks and resource adequacy needs. This means there could be value in incentivizing customers – especially electrifying customers about to add significant load – to install CLMS devices to clip their peak load even if their panel has adequate capacity. However, there is currently no program or pricing mechanism in place in New York to compensate customers for this type of permanent and reliable demand clipping. As New York considers refinement of grid flexibility policies, it could be valuable to incorporate CLMS into existing demand response programs or other mechanisms such as non-wire alternative procurements.

In addition, CLMS that can communicate with utility systems can enable flexible interconnection of new loads and DERs[63]. Flexible interconnections are agreements between the utility and the customer to operate the customer's load/DER within prescribed import/export limits. These limits, referred to as "operating envelopes", are defined by the utility based on available distribution system capacity. Operating envelopes may be fixed at the time of interconnection or time-varying based on real-time available capacity ("dynamic operating envelope[64]").

Flexible interconnections can be used to avoid or defer local distribution system upgrades that may otherwise be needed to support new load or DER connection. These local distribution upgrades generally cannot be avoided by other, less controllable types of flexibility measures because each secondary distribution asset serves a very small number of customers.

[61] Highlights of IEEE Standard 1547-2018

[62] All About Home Electrical Panels - NYSERDA

[63] Flexible Distributed Energy Resources Electric Vehicle Connections July 2024

[64] On the Calculation and Use of Dynamic Operating Envelopes - Australian Renewable Energy Agency (ARENA)

For example, a secondary transformer may serve 3 to 10 homes. When these homes electrify, the only way a transformer upgrade can be avoided or deferred is if there is a reliable way to ensure that multiple EVs do not charge at full power at the same time. This type of coordination is unlikely to be reliably achieved across such small cohorts of customers through voluntary customer response to prices or event notifications. However, with operating envelopes implemented through CLMS, customer loads can be reliably managed such that total load (or generation) remains within the local distribution system's maximum capacity.

Internationally, several jurisdictions are in the more advanced stages of implementing flexible interconnection and dynamic operating envelopes for loads. This type of system architecture has recently been mandated by law in Germany[65]. The German system architecture will be implemented through a set of customer-sited devices consisting of an advanced meter, a communications gateway module to interface with external market participants and the network operator, and a control module to interface with customer appliances. According to Germany's Energy Industry Act, the primary goals of implementing controllable grid connections are to improve reliability and to avoid delays in connecting new loads by managing loads within available grid capacity. This type of control is intended to be used only in constrained locations as an interim measure while local grid upgrades are completed and capacity is expanded.

Flexible interconnection approaches for DERs are in the early stages of piloting in New York and other U.S. jurisdictions. In New York, NYSEG and RG&E are conducting a pilot project demonstrating flexible interconnection for four DER projects with a total of 17 MW of DER capacity[66]. There is very limited experience on flexible interconnection for loads in the U.S., and it is unclear if large-scale implementation would be acceptable to customers and policymakers. Southern California Edison recently received approval to conduct a pilot to test the use of flexible interconnection for EV chargers in constrained locations on the distribution grid[67]. Further testing of flexible load interconnection for deferral of secondary distribution upgrades could be a valuable option for exploration in future pilot projects in New York. NYSERDA has awarded funding for the development and commercialization of next-generation MSAs that further enable DERs interconnection and grid services[68].

E. Thermal Energy Networks and Thermal Energy Storage

Thermal energy networks (TENs) are networks of pipes that facilitate the exchange of heat between various sources and sinks. Sources and sinks could include geothermal exchange, water bodies, wastewater, waste heat from buildings, thermal storage, building HVAC systems, and data center cooling systems, among others. TENs can be used for heating, cooling, and domestic hot water in

65 Federal Network Agency - §14a EnWG Controllable consumption equipment

66 Flexible Interconnect Capacity Solution (FICS) Reforming the Energy Vision (REV) Demonstration Project Intermediate Summary Report.

67 SCE Advice Letter 5138-E

68 ConnectDER Awarded NY State Funding to Develop Next Generation DER Connection Solutions - ConnectDER

buildings. They can be designed to be 100% clean, and by incorporating sources of waste heat, can utilize less electricity compared to other clean heat sources like standalone heat pumps. The decarbonization of buildings is an important component of New York's climate roadmap, and TENs are one of the options to reduce emissions from building heating and cooling.

TENs also have the potential to be grid flexibility resources. They can be deployed in a targeted manner in areas that may be difficult to electrify with standalone heat pumps due to grid capacity constraints or building characteristics, thereby reducing potential infrastructure upgrade costs. They can also be targeted in areas that have abundant sources of waste heat, such as around data centers. Utilization of waste and other sources of heat can reduce the electricity needed to meet heating and cooling demands, including at peak periods for the electricity grid. In addition, depending on the configuration of TENs, they may be able to dynamically switch between different heat sources and sinks in response to electric grid needs.

Thermal energy storage (TES) systems are another option for providing grid flexibility through optimized heating and cooling, either on a standalone basis or as a part of a TEN. A TES system can use electricity during low-price periods to store heat and then utilize the stored heat during high-price periods to reduce grid costs. TES can also be responsive to grid signals on short notice, enabling them to provide grid balancing services such as ramping. A recent study prepared by Brattle for the Center for Climate and Energy Solutions and the Renewable Thermal Collaborative found that the use of "thermal batteries" powered by renewable generation to provide heat to industrial processes could be cost-competitive with conventional sources (i.e., natural gas) if given better access to wholesale energy markets or more cost-reflective retail rate structures.[69]

New York has been leading the deployment of TENs in the U.S. through its Thermal Energy Networks and Jobs Act[70], passed in 2022. The Act directed each of New York's seven largest investor-owned utilities to develop pilot TEN projects in their service territories. Twelve of the projects the utilities proposed, totaling $880 million, have been approved and are now in active development[71]. These pilot projects will yield many important insights on the technical and regulatory frameworks needed for them to be operationally and commercially viable. It is likely that the initial focus of the pilot projects will be to test and refine the foundational aspects of TENs, including the customer experience, operational reliability, and financial viability. As the foundational aspects become well-established, the pilot projects could begin to test the technical feasibility and program/price mechanisms needed to enable the TENs to be utilized for grid flexibility.

As TENs scale in the long-term, it will be important to establish protocols for economically efficient and coordinated operation and planning with the electric grid. With the right policies in place, TENs that can provide grid flexibility could be an important option to cost-effectively manage a winter-peaking electricity grid. Correspondingly, receiving appropriate compensation for providing grid flexibility could be an important aspect in ensuring the financial viability of TENs.

---

69 Thermal Batteries: Opportunities to Accelerate Decarbonization of Industrial Heat

70 NY State Senate Bill 2021-S9422

71 PSC Adopts Initial Utility Thermal Energy Networks Rules | Department of Public Service

F. Large New Loads with Microgrids

Like much of the rest of the U.S., New York is forecasting an increase in electricity demand driven in part by the emergence of new "large load" customers. NYISO's 2024 Reliability Needs Assessment estimated that large loads would contribute between 2.2 and 3.0 GW to statewide peak demand between 2024 and 2034.[72] Much of that new load is expected to come from manufacturing facilities, data centers, and hydrogen facilities predominately located in in Upstate NY. At the time of the 2024 Reliability Needs Assessment, NYISO had existing interconnection requests from 19 projects amounting to 3 GW of new load.[73]

These large load customers could become a significant new source of flexibility. While our Grid Flexibility Potential Study accounted for a basic level of grid flexibility that could be provided through both manual and automated DR systems from large customers, the potential for flexibility from new large loads would be mostly additive to that estimate. More specifically, the incremental flexibility potential could be derived from on-site generation that is likely to be adopted by these customers.

Large loads increasingly are exploring the potential to serve their electricity needs entirely through on-site generation configured as a microgrid, at least until a connection to the broader power grid is available. This is emerging as a particularly pragmatic solution for new hyperscaler data centers, which are prioritizing speed to power but are delayed by limits on the availability of transmission and generation capacity. Beyond the benefit of accelerating speed to power, large loads often require some form of on-site generation to ensure a high level of reliability even when connected to the power grid.

That on-site generation could be used to provide flexibility to the New York power system.[74] One possibility is to use the on-site generation to provide the equivalent of demand response services by serving the customer's load locally and reducing or even eliminating the power the customer draws from the grid during a demand response event. That approach could provide capacity, energy, and ancillary services benefits, or potentially reduce the size of the customer's interconnection to the grid.[75] The on-site generation also could export to the grid, if configured appropriately.

Providing grid services from on-site generation could have several benefits to the participating customer. The compensation for those services could improve the affordability of the on-site generation, thus reducing the cost of acquiring increased resilience. If used to provide firm demand reductions, this model also potentially could accelerate interconnection in areas where capacity is available but limited. The customer would not sacrifice resilience by participating in this type of program, because the generators would continue to supply the customer locally if there is a grid outage.

There are already some emerging examples of this model. For example, in Texas, Entergy partnered with a microgrid developer called Enchanted Rock in its "Power Through Initiative". The program

---

[72] NYISO, 2024 Reliability Needs Assessment.

[73] NYISO, 2024 Reliability Needs Assessment.

[74] A majority of projects in the NYISO interconnection queue exceed 100 MW. Given the scale of new large loads, in many cases the customers are transmission connected. For this reason, it is less likely that the microgrids will provide distribution benefits. However, at a smaller scale there could be distribution benefits.

[75] J. Jeff, One Way Data Centers can Help the Grid? By Being Flexible. Canary Media, 2025.

deploys on-site backup generation for a large commercial customer. Enchanted Rock built and will maintain the generator, which will be owned by Entergy. The generator will be run synchronously with the grid to provide grid services if needed but can also operate in "island mode."[76]

The potential scale of this solution in New York could be large. To illustrate, if 5 GW of new large loads were to connect to the New York power grid by 2040, half of those have on-site generation covering their peak demand, and half of those adopt a model in which the on-site generation provided grid services during peak hours, that would amount to over 1 GW of new, dependable grid flexibility. That would roughly double the amount of C&I demand response currently available in New York utility programs.

Among the barriers, air quality permitting constraints and broader state and corporate decarbonization goals largely prevent this type of flexibility from being provided by diesel units, which are the most common type of backup generation currently. Developers likely will need to be willing to invest in gas generation or other, cleaner sources of generation in order to run the units with the frequency needed to support the grid. If there is sufficient land availability, solar and storage could be included in the mix of on-site assets.[77] Further, the gas generators potentially could be fueled by renewable natural gas.[78]

Another barrier that will need to be overcome is complexity, both from a technical and regulatory perspective. Large loads will need to become comfortable with the notion that applying the on-site generation to a variety of use cases will not reduce its dependability. Complex regulations also will need to be navigated - and potentially changed - to accommodate this new model.

V. Grid Flexibility Considerations for Low Income Customers and Disadvantaged Communities

The CLCPA's targets include a requirement that 35% (with a goal of 40%) of the benefits from these policies directly serve disadvantaged communities (DACs).[79] DACs are defined by the CLCPA as communities that experience higher health risks, environmental pollution, and negative impacts of climate change, while also hosting high concentrations of low- and moderate-income (LMI)

[76] Entergy, Entergy Texas and Enchanted Rock partner on new reliability and resiliency pilot, 2019.

[77] Kyle Baranko, Duncan Campbell, Zeke Hausfather, James McWalter, and Nan Ransohoff, "Fast, scalable, clean, and cheap enough," December 2024. https://www.offgridai.us/.

[78] For example, Microsoft recently announced that a data center in California will be powered by a gas microgrid during outages and for participation in a demand response program. Renewable natural gas will be injected into the gas pipeline upstream of the microgrid. For more information: https://www.microgridknowledge.com/commercial-industrial-microgrids/article/33016385/microsoft-tapping-into-microgrids-and-rng-to-power-data-center-during-grid-outages.

[79] NYSERDA, Disadvantaged Communities Investments and Benefits Reporting Guidance, November 2023.

households.[80] According to the Climate Justice Working Group (CJWG), 35% of New York State's census tracts qualify as DACs.[81] Given these communities' vulnerability to climate impacts, ensuring that they are included in grid flexibility programs is important to mitigate further inequalities and support resilient communities. This section of the report discusses some of the challenges that may prevent LMI and DAC customer segments from benefitting from grid flexibility and options for mitigating those barriers. We also identify additional data that would be needed to extend a future iteration of the Grid Flexibility Potential Study to quantitatively address opportunities for these customer segments.

A. The Importance of a Tailored Approach for DAC Participation

Studies show that low-income households experience high energy burdens—the percentage of a household's income spent on energy bills.[82] The American Council for an Energy-Efficient Economy (ACEEE) reports that in New York City, the median energy burden for low-income households is 9%, compared to the city-wide median among all households of 3%. A quarter of low-income households have an energy burden above 17% in the New York City metropolitan area.[83]

Across the nation, nearly a third of the households had difficulty paying their energy bills or keeping their homes at a healthy temperature in 2020.[84] LMI households may limit their energy use because of concerns about energy bills and may not be able to afford sufficient heating or cooling during extreme temperatures.[85] In the Northeast, households with an annual income less than $60,000 typically consume 27% less electricity than their higher-income counterparts,[86] which may be partially (although not entirely) attributed to energy usage-limiting behavior. Studies have shown that households that limit

---

[80] Households with less than 60% of the State Median Income (SMI) qualify for low-income energy assistance programs in New York. Source: New York Office of Temporary and Disability Assistance, Local Commissioners Memorandum, 2024-2025 Home Energy Assistance Program (HEAP), November 7, 2024. According to this definition, approximately 30% of New York households would qualify as low-income households.

[81] DAC criteria were developed by the Climate Justice Working Group and are reviewed annually. More details can be found on New York Climate Act's webpage.

[82] ACEEE, How High Are Household Energy Burdens? An Assessment of National and Metropolitan Energy Burdens across the U.S.? September 10, 2020.

[83] ACEEE, Energy Burdens in New York City, September 2020.

[84] US Energy Information Administration, Today in Energy: In 2020, 27% of U.S. households had difficulty meeting their energy needs, April 11, 2022.

[85] S. Cong, D. Nock, Y. Qiu, B. Xing, Unveiling hidden energy poverty using the energy equity gap, *Nature Communications* 13: 2456, 2022.

[86] U.S. Energy Information Administration, 2020 Residential Energy Consumption Survey, Oct 2020. In New York State, customers qualify for the federal Low Income Home Energy Assistance Program if their household income below 60% of the State Median Income (SMI). 60% SMI is approximately $52K two-person households and $77k for four-person households for 2025 fiscal year according to New York State Median Income for FFY 2025 | The LIHEAP Clearinghouse.

energy use for cooling during hot summer months or rely on outdated, inefficient appliances may face health risks such as heatstroke. [87]

The challenge is particularly acute for homes in older buildings that are less energy efficient and require more energy to maintain comfortable temperatures. These conditions further exacerbate the difficulties that disadvantaged communities face when attempting to participate in grid flexibility programs. DAC residents also experience higher local air pollution levels, making the benefits of grid flexibility programs, which reduce peaker plant use, especially important in improving their air quality and health outcomes.[88]

Grid flexibility programs often leverage the adoption of enabling technologies such as smart appliances, energy storage systems, and EVs. However, LMI and disadvantaged communities often face significant barriers to accessing these technologies primarily due to financial constraints, such as limited capital and limited access to financing options, living in rental housing, lack of awareness, and lack of time to learn about programs. Renters, in particular, encounter obstacles such as limited ability to install rooftop solar panels or batteries, as landlords are hesitant to pay for upgrades that do not benefit them. This presents a significant barrier to participation in many grid flexibility programs.

Disadvantaged communities often have older, less energy-efficient homes that may require electrical upgrades to accommodate new flexible electric end-uses, increasing the cost of adopting new technology. These communities can also face challenges with limited Wi-Fi and cellular coverage, which can hinder participation in grid flexibility programs that rely on Bluetooth connectivity. Overcoming these barriers requires recognizing and addressing the unique challenges faced by the DAC segment.

Grid flexibility program design can incorporate the unique needs of DAC households by accounting for differences in electricity usage, technology adoption, and participation. By creating customized strategies and allocating targeted funds to address these specific needs, program designers can more effectively engage the LMI and DAC communities, ensuring that they fully participate in and benefit from grid flexibility initiatives.

B. Potential Features of a Tailored Approach

For LMI and DAC households looking to adopt technologies that enable grid flexibility, lack of accessible financing remains a significant barrier. Many households replace appliances on an emergency basis every 10 to 20 years and choose the lowest cost options, which are less likely to have the connectivity features required for grid flexibility. Providing easily accessible financing is one important strategy to broaden the inclusivity of grid flexibility offerings.

---

[87] L. Huang, D. Nock, S. Cong, Y. Qiu, Inequalities across cooling and heating in households: Energy equity gaps, *Energy Policy* 182: 113748, 2023.

[88] PEAK Coalition, The Fossil Fuel End Game: A Frontline Vision to Retire New York City's Peaker Plants by 2030, October 2024.

Low interest loans and on-bill payment mechanisms allow customers to repay loans to utilities or third-party lenders via line items on their electricity bill. NYSERDA's residential financing program offers on-bill tariff loan programs for up to $25,000 for PV systems, heat pumps, and energy efficiency improvements.[89] However, the reach of these loan programs has been limited, with the maximum annual market penetration from the loans only reaching 0.1% of households in New York.[90] Furthermore, the majority of participants in the NYSERDA loan program were above 60% of the state median income and had high credit scores, demonstrating the need for specific programs targeting LMI and DAC customers.[91]

Another example of innovative loan structures is in California. AVA Community Energy (formerly MCE) is a community choice aggregator. In partnership with local organizations, AVA Community Energy used a $3 million grant from the California Energy Commission and city-wide social impact bonds to create a grid flexibility program in Richmond, a historically disadvantaged community. Residents will receive zero-interest loans to finance equipment and installation costs, as well as monthly credits for allowing AVA to reduce load in peak hours.[92] Nonpunitive incentive structures such as on-bill credits and peak time rebates build trust with the local utility and can be effective in driving behavior change.[93]

Equity-focused grants and incentives can support energy affordability in LMI and DAC areas. For instance, when Inflation Reduction Act (IRA) rebates became available, the adoption potential of heat pump water heaters, heat pump space heaters, and electric cooking ranges more than doubled among LMI households.[94] In New York, PSEG Long Island's residential storage incentive program doubles incentives for LMI customers, in compliance with the 35% goal set by the CLCPA.[95] "First-loss" funding pools built to subsidize financing in LMI and DAC households can further encourage adoption and can be funded through savings from grid-flexibility programs.[96] Cost-effectiveness from the customer's

---

89 NYSERDA, Residential Financing Programs, Accessed on March 1, 2025. NYSERDA's EmPower+ program is designed to assist low- and moderate-income homeowners and renters by providing no-cost home energy assessments, installations, and funding for energy efficiency improvements.

90 T. Reames, ACEEE Finance Forum Keynote Remarks, May 2022.

91 J. Dawson, G. Leventis, Long-Term Performance of Energy Efficiency Loan Portfolios, Lawrence Berkeley National Lab, March 2022. The LBNL study analyzed four long term loan program outcomes and found that the majority of loans went to customers with prime credit ratings or above. The cutoff for qualifying for financial assistance on bills in New York is 60% of state median income.

92 Canary Media, These California programs steer solar batteries to low-income households, 2024.

93 PEAK Coalition, The Fossil Fuel End Game: A Frontline Vision to Retire New York City's Peaker Plants by 2030, October 2024.

94 J.M. Joseph, C. Samaras, D. Nock, K.B. Gregory, P. Vaishnav, Rebates and grid decarbonization from the Inflation Reduction Act promote equitable adoption of energy efficiency retrofits, *Environmental Research Letters*, in press, 2024. Adoption potential is a metric used by this article to represent the discounted cost-basis of a technology over a lifetime. Households are identified as potential adopters if they achieve a positive net present value through operational cost savings overcoming the capital expenses.

95 PSEG Long Island, Utility 2.0 Long Range Plan & Energy Efficiency Plan, 2023 Annual Update, Prepared for Long Island Power Authority, July 1, 2023.

96 U.S. Department of Energy, Virtual Power Plants: Pathways to Accelerating VPP Deployment and Growth, September 2023.

standpoint is not a guarantee of adoption, however, as customers may not want to take on the debt required to procure new technology.

Utility ownership and deployment of energy efficiency and grid-flexible technologies is an alternative to customer loans and may be more attractive for LMI and DAC households. On-bill tariffs, or inclusive utility investments (IUI) is one such model in which the utility owns electrification, energy efficiency, and/or grid flexibility equipment that cut down on monthly energy bills. Customers are then charged the cost of the equipment under a tariff (up to a maximum of 80% of the expected cost savings), which allows the utility to recover its costs.[97] Once the equipment costs are paid off, ownership transfers to the customer. Unlike loan programs, on-bill tariff programs do not require credit checks and repayment is tied to utility meters rather than directly to a customer.[98] Usually administered as Pay As You Save (PAYS) programs, on-bill tariffs programs already exist in several U.S. jurisdictions. The potential challenges of such programs include the administrative costs needed to calculate customer-specific tariffs and stakeholder concerns about the merits of utility-ownership of devices located behind the meter.

Local microgrids and community solar and storage projects offer opportunities to LMI and DAC households to access grid flexibility benefits without the need for individual financing. For example, Marcus Garvey Village, an affordable housing complex in Brooklyn with 625 apartments, built a 1.1 MW microgrid that includes a 400 kW PV system, a 400 kW natural gas fuel cell, and a 300 kW battery.[99] Peak energy demand, which can reach 3 MW in winter and 1.5 MW in summer, is lowered by the microgrid and helps residents save 15 to 20% on monthly electricity bills without paying upfront costs. To enable the project, the New York City Energy Efficiency Corporation, a non-profit that finances clean energy and energy efficiency projects, awarded a 10-year loan to the battery developer, Demand Energy, that will be paid back with an incentive payment of $540,000 from Con Edison and revenues generated from peak shaving and demand response.[100]

As mentioned above, low-income households may differ from other households in terms of energy usage and ability to shift load due to having less energy-efficient homes and appliances. As a result, grid flexibility programs targeting low-income customers may not yield the same load shifting as standard grid flexibility programs. Due to lower load shifting benefits, these targeted programs may not appear cost-effective under the traditional benefit-cost analysis tests that the utilities need to conduct to obtain regulatory approval to implement their programs. To increase the likelihood that low-income-focused DR programs pass cost-effectiveness screens, one potential solution is to offer these programs under

---

97 H. Hummel, H. Lachman, What is inclusive financing for energy efficiency, and why are some of the largest states in the country calling for it now? Energy Efficiency Institute, Clean Energy Works, 2018. If the levelized cost of the technology is less than 80% of savings, then the costs can be reduced.

98 By regulatory mandate, this deal is extended to the next owner of the building if the original participant moves out.

99 More information on the climate resilience benefits can be found in the New York State Climate Impacts Assessment, Case Studies, Innovative Housing Microgrid for Community Resilience at Marcus Garvey Village, Accessed on March 1, 2025.

100 NYCEEC, Financing battery storage for the nation's first affordable housing microgrid, A NYCEEC Case Study, 2017.

the low-income program portfolio, rather than the standard demand response portfolio, since low-income programs typically do not require the same benefit-cost tests. The costs and benefits however should be tracked to ensure efficient program delivery.[101]

Besides financial constraints, individuals in LMI and DAC households may face time constraints due to multiple jobs, caregiving responsibilities, or other socioeconomic challenges (also referred to as "time poverty" [102]). Therefore, streamlining enrollment in grid flexibility programs is key. Combining different types of grid flexibility programs (e.g., bill payment assistance, rate options, energy efficiency, and grid participation) into one streamlined package can greatly simplify and boost enrollment. Automatically enrolling customers (while providing an opt-out option) when purchasing grid-connected technologies could further alleviate time poverty as well as boost overall enrollment, resulting in increased benefits for consumers and the grid. Where income eligibility is a factor in program participation, conducting income verification alongside other assistance programs such as the Supplemental Nutrition Assistance Program (SNAP), transit, or energy assistance programs can also expedite the process, reducing the administrative burden on both customers and utilities. This integration simplifies access to multiple services and reduces friction during the enrollment process.

Local workforce development and culturally appropriate program information is also critical. To effectively engage all communities, program outreach materials should be translated into multiple languages and provided in a manner that respects local customs and needs. Partnering with local community organizations is an essential strategy for building trust, improving outreach, and supporting local job growth in positions such as electrical work or IT. These groups can help educate residents about the benefits of grid flexibility programs and guide them through the enrollment process.[103] In New York, organizations such as the Brotherhood of Electrical Workers (IBEW) and the National Electrical Contractors Association (NECA) can provide partnerships leading to certifications and jobs that can enable DAC communities to participate in the workforce that will be needed for New York's energy transition.[104]

C. Information Needs for Assessing Grid Flexibility Potential for Low-Income and Disadvantaged Communities

A useful future extension of the Grid Flexibility Potential Study could include quantitative analysis focused specifically on opportunities for the LMI and DAC customer segments. However, based on our

[101] A. Farabaugh, Implementing Load Flexibility Programs To Help Alleviate Low-Income Energy Burden, ACEEE Summer Study on Energy Efficiency in Buildings, 2024.

[102] C. Vickery, The Time-Poor: A New Look at Poverty, *The Journal of Human Resources* 12:1, 1977.

[103] PEAK Coalition, The Fossil Fuel End Game: A Frontline Vision to Retire New York City's Peaker Plants by 2030, October 2024.

[104] Ibid.

review of available New York-specific data, information gaps will need to be addressed to complete that analysis.

To develop DAC and LMI specific grid-flexibility potential estimates, forecasts for customer counts and electrification appliance saturation are needed. Information on incentive-based enrollment behavior and customer load shapes by end use technology will also be important because housing stock, dwelling type, and appliance ownership may differ significantly between DAC and non-DAC households. One option to make DAC data readily accessible is for the Integrated Energy Data Resource (IEDR) – a centralized tool hosting New York energy data[105] – to gather and share relevant data.

Ongoing studies and pilot projects will help refine strategies for improving LMI and DAC participation in grid flexibility programs, as well as develop robust financing mechanisms that enable widespread adoption. By studying existing programs and exploring new financing models, utilities and policymakers can address key barriers and ensure that LMI and DAC customers are fully included in New York's grid flexibility future. By focusing on inclusive, accessible, and flexible solutions, grid flexibility programs can contribute to meeting both New York's climate goals and the energy needs of its most vulnerable populations.

VI. Appendix A: Sensitivity Analysis Details

We model grid flexibility programs individually to arrive at cost-effective statewide portfolios for each sensitivity described in Section 2 of this report. This Appendix describes the program level inputs we used to model the sensitivity cases. We summarize inputs at a statewide level, but model programs at the utility level consistent with the methodology documented in the Volume I and II reports in this series. These inputs capture the range of uncertainty around the evolution of technological, market, and customer conditions in New York by 2040.

For each sensitivity, we adjusted inputs in isolation relative to the base case to quantify the impact of key variables. We vary each base case input to test favorable grid flexibility conditions (high value case) and less favorable inputs (low value case). This section of the report documents assumptions for the high and low sensitivity cases and we include the base case assumptions for reference.

A. Participation

Participation rates are based on observed levels achieved in operational pilots and programs across New York and other jurisdictions whenever possible. The participation rates shown in Table 2 are tailored to

[105] NYSERDA, Integrated Energy Data Resource (IEDR) Program, Accessed March 4, 2025.

the cost-effective participation incentive level. Cost-effective participation rates are shown as if programs were offered in isolation, before adjusting for portfolio overlap.

TABLE 2: COST-EFFECTIVE ACHIEVABLE PARTICIPATION RATES (% OF ELIGIBLE CUSTOMERS, STATEWIDE 2040)

Class	Grid Flex Option	Base	High	Low
Residential	Cooling	34%	52%	23%
	Heating	32%	52%	19%
	Heat pump water heating	31%	56%	25%
	Electric resistance water heating	39%	58%	26%
	Time-varying rate (opt-out)	80%	90%	60%
	Time-varying rate (opt-in)	20%	30%	5%
	Behavioral DR	80%	90%	60%
	EV time-of-use (TOU)	40%	50%	15%
	EV managed charging—home	32%	52%	13%
	EV vehicle-to-grid (V2G)	10%	20%	5%
	EV managed charging—workplace	1%	1%	0.2%
	BTM battery storage	~1.1 GW (2% of class)	~1.7 GW (3% of class)	~0.6 GW (1% of class)
Small C&I	Cooling	10%	14%	4%
	Heating	16%	22%	6%
	Time-varying rate (opt-out)	80%	90%	60%
	Time-varying rate (opt-in)	10%	25%	5%
Large C&I	Manual DR	37%	62%[106]	25%
	Auto DR	25%	37%	12%
All C&I	BTM battery storage[107]	~240 MW	~300 MW	~100 MW

B. Eligibility

The Climate Leadership and Community Protection Act (CLCPA) outlines a goal of 85% building electrification by 2050. In the high potential case, we assume the decarbonization goal is met, similar to

[106] Based on DOE study of commercial demand flexibility adoption

[107] The same relative participation levels for residential and C&I storage is assumed.

the base case, but customers adopt smart control equipment like smart thermostats and BTM storage faster than current adoption predications. For the low case, we assume CLCPA targets are met but delayed by 5 years. Table 3 below shows the percent of customers statewide assumed to have adopted technologies that vary across the sensitivity cases.

TABLE 3: INPUT ELIGIBILITY RATES (% OF TOTAL CUSTOMERS IN CLASS, STATEWIDE 2040)

Class	Grid Flex Option	Base	High	Low	% of	Customer Technology
Residential	Cooling[108]	57%	57%	57%	Total class	Central cooling
	Smart thermostat – cooling	39%	46%	39%	Total class	Cooling control
	Heating	62%	62%	40%[109]	Total class	Central electric heating
	Smart thermostat – heating	54%	59%	33%	Total class	Heating control
	Heat pump water heating	83%[110]	83%	60%	Total class	Heat pump water heater
	Electric resistance water heating	8%[111]	8%	8%	Total class	Electric resistance water heater
	Time-varying rate & behavioral DR	100%	100%	100%	Total class	Smart meter
	EVs[112]	79%	79%	52%	All light-duty-vehicles (LDVs)	Light duty EV
	BTM battery storage		See text below			
Small C&I	Cooling	80%	80%	80%	Total class	Central cooling
	Smart thermostat – cooling	39%	64%	39%	Total class	Cooling control
	Heating	62%	62%	47%	Total class	Central electric heating
	Smart thermostat – heating	52%	59%	38%	Total class	Heating control
	Time-varying rate	100%	100%	100%	Total class	Smart meter
Large C&I	Manual DR	100%	100%	100%	Total class	N/A
	Auto DR	100%	100%	100%	Total class	N/A[113]
	BTM battery storage		See text below			

108 We maintain a constant number of customers with grid-connected cooling across all cases but increase the adoption rate in the absence of utility incentives. This change reflects a cost variation, which we model accordingly.

109 Heating programs account for grid-connected heaters. The low scenario assumes fewer customers upgrade to grid connections.

Continued on next page

Our base 2040 assumption that 2% of customers will be enrolled in BTM storage programs is conservative relative to Green Mountain Power's adoption forecast of 4%. In the low sensitivity we assume a 1% enrollment rate and, in the high case, continue to assume adoption will be lower than the Green Mountain Power projection. While battery programs in New York are in the early stages, our high case remains conservative when compared to Green Mountain Power's BTM storage program which has current enrollment of 1% and forecasts 4% to 85 by 2030.[114]

C. Program Operational Characteristics

We vary the per-participant impacts and operational assumptions for each program to account for uncertainty in the potential performance of the grid flexibility options, and the behavioral and technical considerations that may limit their dispatch. Assumptions for all cases are presented in Table 4.

TABLE 4: GRID FLEXIBILITY PROGRAM OPERATIONAL SENSITIVITY ASSUMPTIONS

Program	Base	High	Low
Cooling *(residential and small commercial)*	1 kW impact of Residential Single Family, 0.6 kW impact for Residential Multi-Family, Small C&I impact varies by utility; 4-hour event; 15 events per year	125% impact (relative to Base), 4-hour event, 20 events per year	75% impact (relative to Base), 3-hour event, 10 events per year
Space heating *(residential and small commercial)*	40% of heating load can be reduced, 3-hour event, 15 events per year	60% of heating load can be reduced, 3-hour event, 20 events per year	20% of heating load can be reduced, 3-hour event, 10 events per year
Smart water heating *(electric resistance and heat pump)*	5% opt-out (95% curtailment during events), 3-hour event, 365 days per year	0% opt-out rate (100% curtailment during events), 3-hour event, 365 days per year	10% opt-out (90% curtailment during events), 3-hour event, 200 days per year
EV managed charging *(home and workplace)*	10% opt-out (90% curtailment during events), 365 days per year	5% opt-out (95% curtailment during events), 365 days per year	15% opt-out (85% curtailment during events), 150 days per year
EV time-of-use (TOU) *(home)*	80% of charging occurs off-peak	90% of charging occurs off-peak	70% of charging occurs off-peak

[110] All HPWHs are eligible to participate assuming a connectivity standard is in place by 2028 and 10-year lifetime for water heaters.

[111] All ERWH are eligible to participate assuming a connectivity standard is in place by 2028 and 10-year lifetime for water heaters.

[112] EV Programs include EV TOU, EV managed charging at home and at work, and EV V2G.

[113] Customer adoption of Auto-DR technology is accounted for in the participation assumption. All large C&I load is assumed eligible to participate.

[114] See additional information in Green Mountain Power's 2021 Integrated Resource Plan.

EV vehicle-to-grid (V2G) ***(home)***	100 events per year, battery can reduce to 30% charge	150 events per year, battery can reduce to 20% charge	50 events per year, battery can reduce to 40% charge
Time-varying rate ***(residential and small commercial)***	TOU impacts are 4.6% for opt-in and 2.8% for opt-out; CPP impacts are 19.5% for opt-in and 9% for opt-out	Increase base impact by 25%	Decrease base impact by 25%
Behavioral demand response ***(residential)***	3% of hourly load can be reduced	4% of hourly load can be reduced	2% of hourly load can be reduced
BTM battery ***(residential and commercial)***	100 events per year, 20% backup requirement	150 events per year, 10% backup requirement	50 events per year, 50% backup requirement
Auto-DR ***(large C&I)***	30 events per year	45 events per year	15 events per year
Manual DR ***(large C&I)***	30 events per year	45 events per year	15 events per year

D. Avoided Generation Capacity Cost

The cost of future avoided generation capacity is dependent on New York's ability to meet its clean energy goals and the technologies it relies upon to do so. The base case assumes a forecasted capacity cost for New York of $222/kW-year in 2040 (in 2024 dollars) based on NREL Cambium 2023's mid-case with 100 percent decarbonization by 2035 scenario.[115] This NREL scenario includes a supply mix of renewables, battery storage, hydro, and hydrogen combustion turbines, with hydrogen combustion turbines likely being the marginal resource.

To model uncertainty around future generation costs, we model a high scenario with avoided capacity costs 50% higher and a low scenario with 50% lower costs than base. The high capacity cost assumption falls between NREL Cambium's high renewable energy cost scenario[116] capacity price and net CONE estimates for 8-hour storage in the NYISO's demand curve reset.[117] The low capacity cost assumption is similar to net CONE estimates for 2-hour battery storage in the 2024 demand curve reset.[118]

TABLE 5: CAPACITY COST SENSITIVITY ASSUMPTIONS (2024$/KW-YEAR)

Base	High	Low
$222/kW-year	$333/kW-year	$111/kW-year

[115] NREL Cambium 2023 scenarios.

[116] Ibid.

[117] Independent Consultant Study to Establish New York ICAP Demand Curve Parameters for the 2025-2026 through 2028-2029 Capability Years, https://www.nyiso.com/documents/20142/47366127/Analysis-Group-2025-2029-DCR-Final-Report-Updated.pdf.

[118] Ibid.

E. Distribution Capacity Threshold

Utilities across the U.S. and in New York follow different planning standards for allowable maximum loading of different types of distribution assets. Typical loading limits for substations range from 75% to 100% and can be as high as 130%. In a high load growth paradigm, some utilities may revise their criteria downward in order to begin planning for grid upgrades earlier, leaving more buffer for new customers to be connected without delays[119]. To reflect this range of planning practices, we assume a loading limit of 100% in the base case and 75% in the high potential case, thereby expanding opportunities for grid flexibility programs to deliver distribution value.

Utilizing grid flexibility programs for targeted distribution deferral projects requires coordinated, timely deployment and operation of these resources and integration into distribution system planning processes. There has been limited experience with this use case so far, and there is uncertainty around scaling of pilot programs, coordination of distribution and bulk system use cases, and the development of communication and control capabilities needed to utilize flexibility resources for distribution deferral. To reflect this uncertainty in the Low Potential Scenario, we show the impact on grid flexibility potential if grid flexibility programs cannot provide any distribution system value.

F. Avoided Cost Allocation Hours

There is uncertainty in the duration for which grid flexibility will need to be available in order to defer investment in generation, transmission, or distribution capacity. The "avoided cost allocation hours" sensitivity case tests the impact of higher or lower availability requirements on grid flexibility potential. In both sensitivities, we allocate the same $/kW-yr avoided costs for each investment type over different numbers of hours, as described in Table 6.

TABLE 6: MARIGNAL COST HOURLY ALLOCATION SENSITIVITY CASE ASSUMPTIONS

Program	Base	High	Low
Capacity Cost	Top 50 net load hours / season	Top 20 net load hours / season	Top 150 net load hours / season
Distribution Cost	Top 50 load hours / year	Top 20 load hours / year	Top 100 load hours / year
Transmission Cost	Top 100 load hours / year	Top 60 load hours / year	Top 200 load hours / year

[119] Examples of utilities revising their planning criteria downward include Xcel Energy and Eversource Energy

In the base case, we allocate the annualized cost of distribution system capacity over the top 50 hours seasonally. Assuming utilities will have more control and insight into individual feeder peak timings in the high potential case, we reduce the allocation hours to 20 annually, allowing for more concentrated benefits for consumers. In the low potential case, we allocate over 100 hours annually.

Similarly, for marginal generation capacity costs, we allocate costs proportionally over the top 50 net load hours seasonally in 2040. In our high potential case, we reduce the allocation to 20 hours per season, allowing for higher benefits in tight system hours. For the low potential case, we assume 150 hours per season. We scale marginal transmission avoided cost allocations to match capacity cost allocations, resulting in allocating value over 60 hours annually and 200 hours annually in our high and low case, respectively.

G. Program Costs

Program costs considered in this study represent costs incurred by the utility or aggregator to attract participants and operate each program. See the Volume II report for more detail on the base case cost assumptions. For the sensitivity analysis we capture the uncertainty around costs required to control customer end-use devices. Base case and sensitivity case assumptions are documented in Table 7. Cost categories not listed remain unchanged across all three cases.

TABLE 7: PROGRAM COST SENSITIVITY ASSUMPTIONS

Cost Type		Base	High	Low
Equipment	Smart water hearing (electric resistance)	Connectivity costs of $80/participant	Connectivity costs of $100/participant	Connectivity costs of $50/participant
	Smart water hearing (heat pump)	Connectivity costs of $50/participant	Connectivity costs of $75/participant	Connectivity costs of $25/participant
	EV vehicle-to-grid (V2G)	Incremental cost of $8,500 for a bidirectional charger (relative to a standard Level 2 charger), split between utility and customer. Cost declines 2% per year in real terms.[120]	Charger costs decline 0% per year in real terms	Charger costs decline 6% per year in real terms

[120] SEPA's 2023 State of Bidirectional Charging report. We assume the total cost of the charger is shared between the utility and the participant. We assumed bidirectional charger costs decline 2 percent per year in real terms; this is conservative when compared to historic cost declines for L2 chargers (see RMI report). We consider a cost share between the utility and the customer to be reasonable because the customer would experience additional benefits such as vehicle-to-home backup capability.

DERMS	**Contract costs**	Ranges from $50,000 to $400,000 based on utility size[121]	Increase costs by 30% from Base	Decrease costs by 30% from Base
	Per device costs	$24/kW-year cost for cooling, space heating, water heating, EV managed charging, EV V2G, and BTM battery storage programs[122]	Increase costs by 30% from Base	Decrease costs by 30% from Base
OEM	**Per device costs**	None modeled; assume OEM fees decline due to market competition	$10/device for cooling, space heating, and water heating[123] $150/year for EV and storage programs[124]	None

[121] These estimates are highly approximate values used to inform the grid flexibility cost-effectiveness screening analysis and should not serve as a substitute for a more detailed utility technical needs assessment. The estimates are informed by consultation with industry experts and Brattle review of costs in utility dynamic load management (DLM) reports. DERMs contract fees are assumed to vary according to utility size. Contract costs are allocated across all programs based on relative program impact.

[122] Informed by consultation with industry experts.

[123] Informed by National Grid pilot programs.

[124] SEPA's 2024 State of Managed Charging report.