March 31, 2025

Hon. Michelle L. Phillips, Secretary
New York State Public Service Commission
3 Empire State Plaza
Albany, New York 12223-1350
secretary@dps.ny.gov

Re: In the Matter of Proactive Planning for Upgraded Electric Grid Infrastructure – Joint Utilities Proposed Long-Term Framework (Case 24-E-0364)

Dear Secretary Phillips:

Advanced Energy United and The Alliance for Clean Energy New York submits for filing the attached Joint Comments regarding the Joint Utilities' Long-Term Proactive Planning Framework filed on December 13, 2024.

Respectfully submitted,

/s/ Elizabeth Stears
Elizabeth Stears
Principal, Advanced Energy United
1801 Pennsylvania Avenue NW, Suite 410, Washington, DC 20006
(307) 752-5017
estears@advancedenergyunited.org

/s/ Shawn Kelly
Shawn Kelly
Director, Advanced Energy United
1801 Pennsylvania Avenue NW, Suite 410, Washington, DC 20006
(317) 590-8540
skelly@advancedenergyunited.org

/s/ Jed Prickett
Jed Prickett
Clean Energy Analyst, Alliance for Clean Energy New York
119 Washington Avenue, Suite 103, Albany, NY 12210
(703) 715-7544
jprickett@aceny.org

Advanced Energy United and Alliance for Clean Energy New York Comments

Re: In the Matter of Proactive Planning for Upgraded Electric Grid Infrastructure – Joint Utilities Proposed Long-Term Framework (Case 24-E-0364)

Advanced Energy United ("United") and the Alliance for Clean Energy New York ("ACE NY") appreciate the opportunity to submit comments on the Joint Utilities' ("JU's") Proposed Long-Term Framework for Proactive Grid Planning (the "Framework"). We strongly support the New York Public Service Commission's ("Commission's") efforts to transition to a more proactive and forward-thinking approach to grid planning. The recognition that infrastructure investments must anticipate electrification trends is essential for ensuring an efficient, cost-effective, and reliable energy future.

United is a national association of businesses that works to accelerate the move to 100% clean energy and electrified transportation in the U.S. The term advanced energy encompasses a broad range of products and services that constitute the best available technologies for meeting our energy needs today and tomorrow. These include electric vehicles (EVs), energy efficiency, demand response, energy storage, solar, wind, hydro, nuclear, heat pumps (air- and ground-sourced), and smart grid technologies. United represents more than 100 companies in the $374 billion U.S. advanced energy industry, which employs 4.1 million U.S. workers and over 231,600 in the state of New York.

ACE NY is a member-based organization with a mission of promoting the use of clean, renewable electricity technologies, transportation electrification, and energy efficiency in New York State to increase energy diversity and security, boost economic development, improve public health, and reduce air pollution. ACE NY's diverse membership includes companies engaged in the full range of clean energy technologies as well as consultants, academic and financial institutions, and not-for-profit organizations interested in their mission.

The transition to an electrified economy requires a grid that is reliable and resilient while also proactively planned to meet the demands of transportation, building, and industrial electrification. The JU's proposed framework is an important step toward ensuring that New York's electric grid can support the state's clean energy goals. By structuring a consistent, multi-stage planning process, the Framework lays the groundwork for a more transparent, data-driven, and strategic approach to grid investments. However, without key refinements, the Framework risks falling short of delivering the transparency, efficiency, and cost-effectiveness necessary to equitably support customers and stakeholders.

Recommendations

United and ACE NY respectfully request the Commission consider the following recommendations, which is followed by more details on each recommendation:

Load Forecasting & Transparency

- Require standardized bottom-up forecasting
- Ensure policy-compliant scenario planning
- Require publicly available real-time grid capacity maps
- Incorporate long-term forecasting of at least 20 years
- Utilities should file annual reports on EV load profiles and managed charging
- Utilities should adopt consistent forecasting metrics, such as vehicle-miles-traveled for EV demand projections

- Include the capacity needs of school districts in cyclical load forecasts
- Utilities should include sensitivity analysis around the variables that are least certain and will have a large impact on the results of their forecast

Planning & Solutions Design

- Prioritize cost-effective alternatives, such as non-wires alternatives ("NWAs"), energy storage, and hardware and software solutions for both utility and customer side load management, before pursuing costly grid expansion
- The planning process should include tangible efforts to slow load growth in the coming years through energy efficiency initiatives
- Utilities should articulate planning criteria relevant to NWAs and justify any divergences to encourage best practices
- Require utilities to provide reasonably robust alternative analyses as part of cost recovery proposals
- Utilities should demonstrate how their load and planning forecasts account for customer charging behavior, including responses to managed charging programs
- Expand the "Best Practices for Planning an Era of Rapid Load Growth Electrification" section of the Framework to explicitly require evaluation of NWAs
- Utilities need to thoroughly assess cost-effective alternatives before investing in major capital projects

Streamlining Grid Upgrades & EV Charging Interconnection

- Utilities should be required to meet defined interconnection deadlines, modeled after successful approaches in other jurisdictions
- Establish a fast-track interconnection process for EV charging stations in areas with existing grid capacity, and offer flexible interconnection options for customers with phased electrification plans

- Push for more specific interconnection deadlines and a standardized permitting framework for EV charging stations
- Require utilities to report on interconnection timelines and permitting efficiency, holding them accountable for delays
- Account for the interconnection needs to supply greater numbers of electric school buses

Load Forecasting & Transparency

Accurate and transparent load forecasting is essential for cost-effective grid planning that meets the needs of electrification without unnecessary over-investment. The Framework outlines three available load forecasting sources: NYISO studies, utility-generated granular electric demand forecasts, and customer electrification plans or third-party studies[1]. United and ACE NY agree with the inclusion of multiple data sources, which will strengthen the planning process. As an example, we submit an original analysis from RMI (see Exhibit A) using their GridUp EV load forecasting tool paired with hosting capacity data from the JU to evaluate where distribution system assets are most likely to need upgrading most urgently. Bringing additional data sources and analytical efforts into the load assessment process will increase transparency and support more adequately vetted investment proposals.

While the emphasis on multiple data sources in the Framework is important, variations across utilities could lead to inconsistencies, inefficiencies, and missed opportunities for coordinated infrastructure investment. In addition, it will create a layer of difficulty for project developers who are building sites with large upcoming load needs. Establishing clear, standardized best practices for load forecasting will enhance data

[1] *Joint Utilities' Long-Term Proactive Planning Framework*, New York Public Service Commission, Case 24-E-0364, p. 14.

comparability, improve planning accuracy, and support a more cohesive statewide approach to proactive grid upgrades.

Bottom-up forecasting should be a prerequisite for interim cost recovery, rather than merely optional. As noted in the Framework, utilities can currently choose from different forecasting methods without a requirement to integrate bottom-up modeling[2]. Utilities should be required to demonstrate how load and planning forecasts account for customers' charging behavior, including both behavior in response to participation in the utilities' managed charging programs and "naturally managed" charging. The lack of information should not justify assuming 100% on-peak charging; assumptions should be conservative but supported. United and ACE NY recommend that the Commission direct the utilities to file annual reports on EV load profiles and managed charging.

Currently, each utility employs different forecasting methodologies, leading to inconsistencies in planning and investment. To achieve standardization, utilities should adopt consistent forecasting metrics, such as vehicle-miles-traveled for EV demand projections, as referenced in the Framework's load assessment discussion[3]. These metrics would help establish a more reliable and comparable dataset across the state. Furthermore, public access to key load forecasting assumptions and methodologies is essential for ensuring transparency and allowing stakeholders to provide informed input.

The Framework introduces a three-step process for coordinating load assessments, including a pre-cycle technical conference where utilities present their common assumptions[4]. United and ACE NY support this approach as it will provide an

[2] *Id.*
[3] *Id* at p. 19
[4] *Id* at p. 18

opportunity for utilities and stakeholders to develop a shared understanding of electrification needs. However, it does not require utilities to incorporate long-term forecasting of at least 20 years, which is essential for making informed investment decisions that align with the projected electrification growth. The Commission should mandate long-term forecasting as a requirement for proactive planning to ensure infrastructure investments meet future demand. While this step is valuable, it should be strengthened by requiring that utilities document how their assumptions align with state policy objectives and electrification targets. The framework also notes that utility forecasts will help inform the Coordinated Grid Planning Process ("CGPP")[5], but without mandatory policy-compliant scenarios, there is no guarantee that forecasts will fully support New York's decarbonization goals.

Real-time grid capacity maps should be incorporated into the planning process to support site selection for EV charging infrastructure. The Framework acknowledges the importance of understanding localized grid constraints but does not explicitly require utilities to publish capacity data in a transparent format[6]. A publicly accessible grid capacity mapping tool would allow developers, businesses, and policy makers to make informed decisions regarding EV charging station placement and other electrification projects. This would reduce bottlenecks in infrastructure deployment and ensure that investments align with grid capacity constraints.

To meet the state's transportation electrification laws, we also recommend that the utilities' cyclical load forecasts include the capacity needs of the school districts within each utility's service area. The state mandates that all new school buses purchased in New York be zero-emission by 2027 and that all school buses in operation be electric by 2035. As more electric school buses take to the roads in the coming years, as

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Id at p. 6

[6] *Id* at p. 26

required by New York state law, school districts will ultimately be responsible for their charging needs and will require greater grid capacity in school bus depots. For all school districts to comply with this mandate, the power supplied to each school district will need to significantly increase to charge the zero-emission buses. Without more comprehensive load forecasting, there will be a rift between the expectations of the state and the limitations of infrastructure. By forecasting the loads of school districts to account for greater electric school bus adoption in the coming years, the utilities may ensure the electricity demands that are required by the state are served in full.

While the Framework takes steps toward a more proactive planning process, improvements can be made by mandating standardized bottom-up forecasting, ensuring policy-compliant scenario planning, and requiring publicly available grid capacity maps. Without these improvements, forecasting inconsistencies could result in misaligned investments, slower electrification progress, and increased costs for ratepayers. United and ACE NY encourage the utilities to do include sensitivity analysis around the variables that are least certain and will have a large impact on the results of their forecast (and therefore their planned investments). Examples of these variables include EV adoption trajectory, the pace of other forms of load growth (e.g., building electrification), and buildout of the charging network (home vs. workplace vs. public) and the associated charging behavior and location. By running a handful of scenarios that vary these and other important assumptions, the utilities should be able to get a much better sense of which assets need upgrades across most scenarios, building confidence in their proposed plans. With the appropriate level of transparency and oversight, this should help to align stakeholders around the upgrades that are most likely to be needed and distinguish between those that need traditional poles and wires versus those that might be effectively met by NWAs.

Planning & Solutions Design: Evaluate Multiple Options for Increasing Grid Capacity

The Framework includes a planning and solution design process that emphasizes coordination across service territories and identifies best practices for grid electrification. These best practices include long-term design, expandability and phasing, right-sizing, alternative technologies, and optionality[7]. The focus on long-term planning and flexible grid investments represents a critical shift toward building an infrastructure that is both resilient and adaptable to future demands. However, the Framework does not go far enough in requiring utilities to prioritize cost-effective alternatives, such as NWAs, energy storage, and demand-side solutions, before pursuing costly grid expansion. If required, this would help ensure that utilities first maximize existing infrastructure to avoid excessive expenditures that would ultimately be passed on to ratepayers.

Utilities should articulate planning criteria relevant to NWAs and justify any divergences to encourage best practices. Additionally, they should be required to provide reasonably robust alternative analyses as part of cost recovery proposals. This "reasonably robust" standard should be further developed through discovery into current utility criteria and standards.

NWAs, managed charging programs, and vehicle-to-grid ("V2G") integration can provide critical grid flexibility while deferring or eliminating the need for expensive traditional infrastructure projects. United and ACE NY recommend that the Commission require utilities to evaluate and prioritize these flexible, scalable

[7] Id at pp. 22-23

alternatives to mitigate costs for ratepayers and ensure that grid investments are both necessary and efficient.

The Framework acknowledges alternative solutions[8] but does not mandate their consideration in planning decisions. To address this gap, utilities should be required to demonstrate how their load and planning forecasts account for customer charging behavior, including responses to managed charging programs. Managed charging has been successfully implemented in New York and in other states such as California. California's AB2700[9] requires the California Air Resources Board to collect fleet data and share it with electric utilities to inform grid planning. Additionally, SB59[10] authorizes the California Energy Commission to mandate bidirectional charging capabilities in EVs, enhancing grid resilience through V2G technology. In New York, Con Edison has launched the SmartCharge Commerical program[11], which incentivizes commercial charging station operators to schedule EV charging during off-peak hours, reducing strain on the grid. Furthermore, Con Edison's Residential Managed Charging ("RMC") program rewards residential EV owners for charging during non-peak times, supporting system reliability and load balancing[12]. By integrating demand-side management strategies, utilities can shift EV charging to off-peak hours, reducing strain on the grid and lowering costs.

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[8] *Id* at pp. 23-24

[9] *California Assembly Bill 2700 (2021-2022)*, California Legislative Information, https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=202120220AB2700.

[10] *California Senate Bill 59 (2023-2024)*, California Legislative Information, https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=202320240SB59.

[11] *SmartCharge Commercial Program (for Station Owners/Operators)*, Con Edison, https://www.coned.com/en/our-energy-future/electric-vehicles/commercial-electric-vehicle-charging-station-rewards.

[12] *2023 Managed Charging EAM Collaborative Report*, New York Public Service Commission, Case 22-E-0064, May 5, 2023

Furthermore, the “Best Practices for Planning an Era of Rapid Load Growth Electrification[13]” section of the Framework should be expanded to explicitly require evaluation of NWAs. While the Framework lists alternative technologies as a consideration[14], it does not outline specific expectations for utilities to compare grid-enhancing technologies against transitional infrastructure investments. A clearer directive from the Commission would require utilities to thoroughly assess cost-effective alternatives before investing in major capital projects.

The planning process should also include tangible efforts to slow load growth in the coming years through energy efficiency initiatives. While accounting for future grid infrastructure needs, the implementation of energy efficient technology will reduce the overall requirements for infrastructure upgrades and reduce the burden on ratepayers. We encourage the JU to maximize efficiency by implementing solutions found in existing utility efficiency programs. The solutions that have been developed in these programs will play a vital role in the planning stage as outlined by the Framework to maximize energy efficiency in the grid upgrade process.

We also encourage the JU to demonstrate the efforts that they have taken to slow the load growth during stakeholder sessions. Transparency must be a cornerstone of the process outlined in the Framework. To ensure that investments are calculated responsibly and at the lowest possible cost for ratepayers, stakeholders must have the opportunity to voice their opinions on the utilities’ pursuit of demand reduction.

By strengthening the Framework’s requirements for planning and solution design, the Commission can help ensure that grid investments align with best practices in cost management and efficiency. A more structured approach to evaluating alternative

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[13] J*oint Utilities’ Long-Term Proactive Planning Framework*, New York Public Service Commission, Case 24-E-0364, p. 22
[14] *Id* at p. 23

solutions will protect ratepayers from unnecessary expenditures while advancing the state's electrification goals.

Streamlining Grid Upgrades & EV Charging Interconnection

The JU Framework acknowledges the importance of grid upgrades and interconnection for EV charging infrastructure and appropriately identifies interconnection delays as a significant challenge to widespread electrification. However, it does not go far enough in ensuring a streamlined and timely process. Interconnection delays remain a significant barrier to the rapid deployment of charging stations, slowing down transportation electrification and increasing costs for developers and ratepayers. Given the urgency of achieving New York's electrification and climate goals, the Commission must take stronger steps to ensure that utilities expedite interconnection approvals and necessary grid upgrades.

EV charging projects frequently face long wait times for interconnection, delaying implementation and reducing the effectiveness of electrification programs. We support the Framework's recognition that interconnection reform is necessary, and we urge the Commission to adopt additional measures to ensure its improvement. To address this issue, utilities should be required to meet defined interconnection deadlines, modeled after successful approaches in other jurisdictions. For example, Hawaii's utility interconnection performance standards[15,16,17] have created a more predictable

[15] *Hawaii Public Utilities Commission Decision and Order No. 24229*, PUC Docket No. 2006-0497 (Hawaiian Electric Co., Hawaii Electric Light Co., and Maui Electric Co.), May 15, 2008
[16] *Hawaii Public Utilities Commission Decision and Order No. 24164*, PUC Docket No. 2006-0498 (Kauai Island Utility Cooperative), April 23, 2008

[17] Hawaii has established simplified interconnection rules for small renewables and separate rules for all other distributed generation (DG). For inverter-based systems up to 10 kilowatts (kW) in capacity, there is a simple application process for interconnection. Systems must meet all applicable performance and

process, ensuring that projects move forward without unnecessary delays. Similarly, California's AB 970 establishes clear time limits for permit approvals, streamlining the permitting and interconnection process for EV charging infrastructure. New York must adopt similar measures to ensure that utilities do not impose excessive delays on critical electrification projects.

Additionally, the Commission should establish a fast-track interconnection process for EV charging stations in areas with existing grid capacity. The Framework acknowledges the importance of grid capacity assessments[18], but it does not require utilities to take proactive steps in facilitating interconnections where capacity is already available. A fast-track mechanism would allow projects in capacity-ready locations to be approved more quickly, reducing bottlenecks and accelerating deployment.

The Framework must also push for more specific interconnection deadlines and a standardized permitting framework for EV charging stations. United and ACE NY recommend that the Commission require utilities to report on interconnection timelines and permitting efficiency, holding them accountable for delays that could hinder progress toward New York's transportation electrification goals. Without clear oversight and defined deadlines, interconnection delays will continue to be a major barrier to EV adoption in the state.

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safety standards from the Institute of Electrical and Electronics Engineers, Underwriters Laboratories, National Electric Code, and where applicable, public utilities commission rules. For other smaller systems, there are simplified interconnection procedures for net metered systems powered by solar, wind, biomass and hydroelectric up to 50 kW.

[18] *Joint Utilities' Long-Term Proactive Planning Framework*, New York Public Service Commission, Case 24-E-0364, p. 26

The interconnection needs to supply greater numbers of electric school buses must also be accounted for in the proposed Framework. For New York to meet its school bus electrification deadlines, a significantly greater number of chargers will be required in each school district. It is vital that school bus depots are incorporated in the development of a more developed interconnection process. The energization demands that electrified school bus fleets will bring are substantial. We therefore urge the utilities to take the opportunity of transportation electrification infrastructure development to prepare for the transition to electric school buses.

By implementing these improvements, the Commission can ensure that interconnection processes support the rapid and efficient buildout of EV charging infrastructure, ultimately reducing costs and accelerating the state's electrification goals.

Conclusion

We appreciate the opportunity to provide input on the JU Framework and look forward to the Commission's order on this matter. We commend the Commission and JU for taking this critical step toward a more modern, proactive, and transparent grid planning process. By refining the Framework's approach to standardization, scenario planning, and interconnection efficiency, the Commission can help ensure that New York's grid investments fully align with the state's decarbonization and electrification goals.

Exhibit A

Anticipated EV Load Growth and Implications for Distribution System Planning

RMI Analysis | Case 24-E-0364 | March 2025

Introduction

RMI used our GridUp Electric Vehicle (EV) Load Forecasting tool paired with utility hosting capacity data to evaluate areas where EV load growth is most likely to necessitate distribution system upgrades. Due to data availability, we focused this analysis on the service territories of two of the Joint Utilities, specifically Consolidated Edison (Con Ed) and National Grid.

Our findings suggest that strategically pursuing proactive distribution system upgrades will be essential to meet expectations for EV load growth, considering its timing and magnitude. For example, our analysis finds that three network substations in the Con Ed service territory will have between 20-60 percent of their currently available capacity taken up by EV load alone by 2030. By 2035, we forecast that two network areas will experience EV load equivalent to or greater than 100 percent of currently available substation capacity. Similar capacity constraints will manifest in National Grid's service territory: by 2030 we expect that seven substation banks will see EV load growth equivalent to 50 percent or more of their currently available capacity. By 2035, 14 substation banks may see EV loads over 100 percent of their current headroom, with four banks over 200 percent.

When considering other forms of anticipated load growth such as building electrification – which are not directly incorporated in our analysis – this suggests that proactively planning for and investing in needed, long-lead time capacity upgrades will be critical to ensure timely service can be provided to all customers. Additionally, the successful implementation of load management strategies can offer significant benefits through deferring and/or reducing the need for asset upgrades. Our analysis considers a managed charging scenario and the effect load management strategies can have on capacity upgrade needs, finding significant reductions in the proportion of available distribution asset capacity that will be required for EV load relative to an unmanaged charging scenario.

EV Load Forecast

GridUp is a publicly accessible tool developed by RMI that identifies where EV load growth is likely to materialize at a detailed geospatial granularity. The power of the tool's underlying methodology lies in its use of localized trip data from today's (primarily) internal combustion engine vehicles to model where tomorrow's electric vehicles are likely to require charging infrastructure, assuming minimal changes to driving behavior.

Extracting load forecasts from GridUp for the service territories of Con Ed and National Grid in New York State highlights both the magnitude and speed with which EV charging demands are likely to materialize (Figures 1 and 2).

Basalt, CO / Boulder, CO / New York, NY / Oakland, CA / Washington, D.C. / Beijing, China

rmi.org / 303.567.8716 / engage@rmi.org

Figure 1. Estimated EV Load, Con Ed Service Territory – Unmanaged Charging Scenario

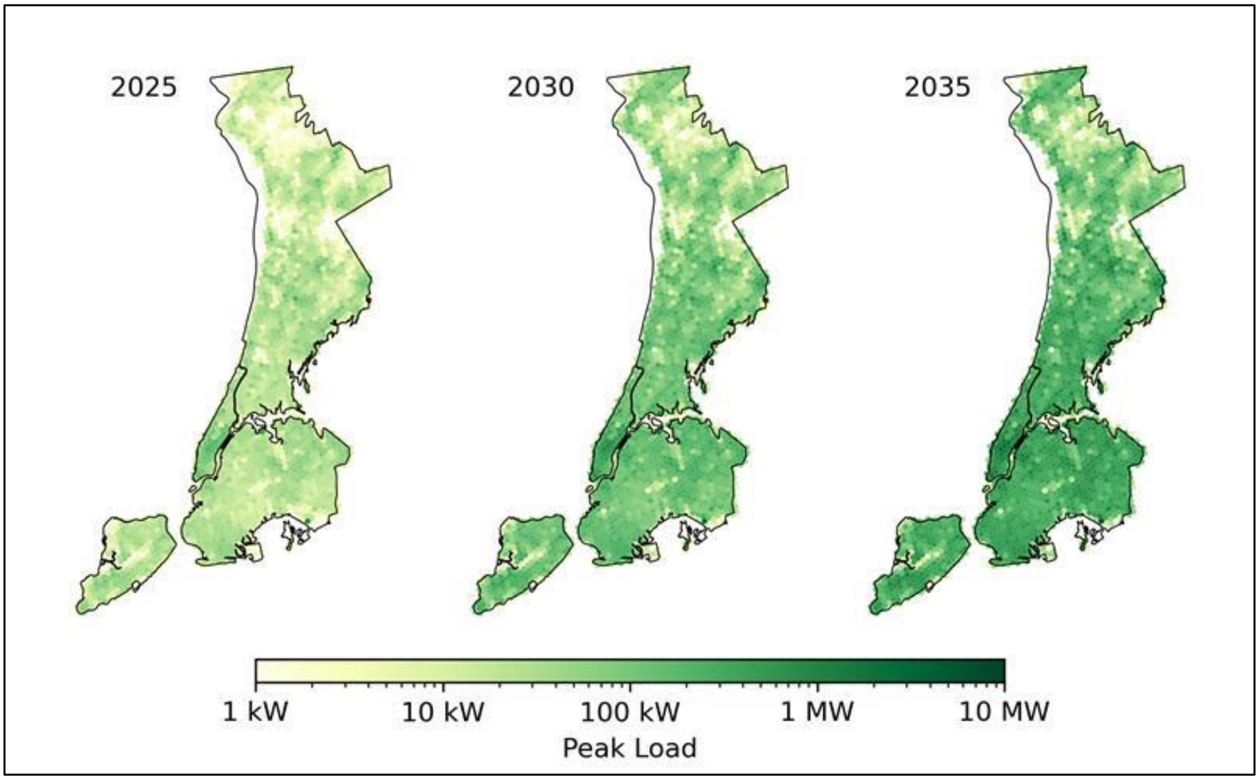
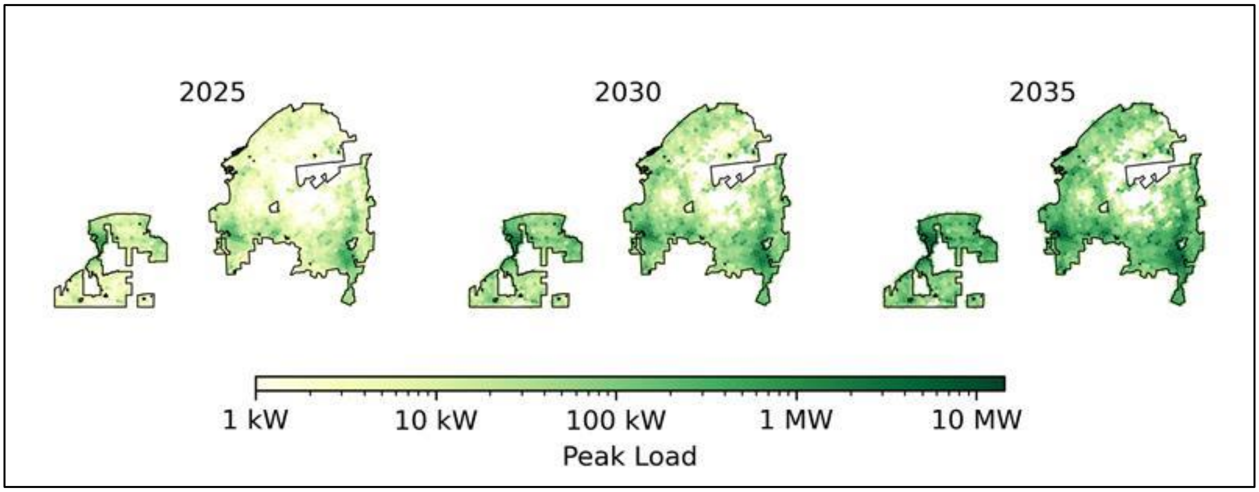


Figure 2. Estimated EV Load, National Grid New York Service Territory – Unmanaged Charging Scenario



Note that EV load growth will not be uniform across utility service territories but rather will be concentrated in particular areas – especially those with significant fleet activity, such as warehouse districts, transit centers, and ports. Examples of these areas include JFK and LaGuardia airports, Maspeth and Sunnyside in Queens, Hunts Point in the Bronx, and Sunset Park in Brooklyn within Con Ed's territory, as well as Erie, Onondaga, Albany, and Saratoga counties in National Grid's territory.

Anticipated Distribution System Asset Overloads

To pair these vehicle-based estimates of EV load growth and location with the electric grid's ability to support it we leveraged publicly available hosting capacity data from Con Ed and National Grid. While two slightly different methods were used in the two utilities' service territories based on the structure and detail of data available, the analysis provides similar outputs, albeit at a finer resolution for National Grid.

This analysis followed the steps outlined below:

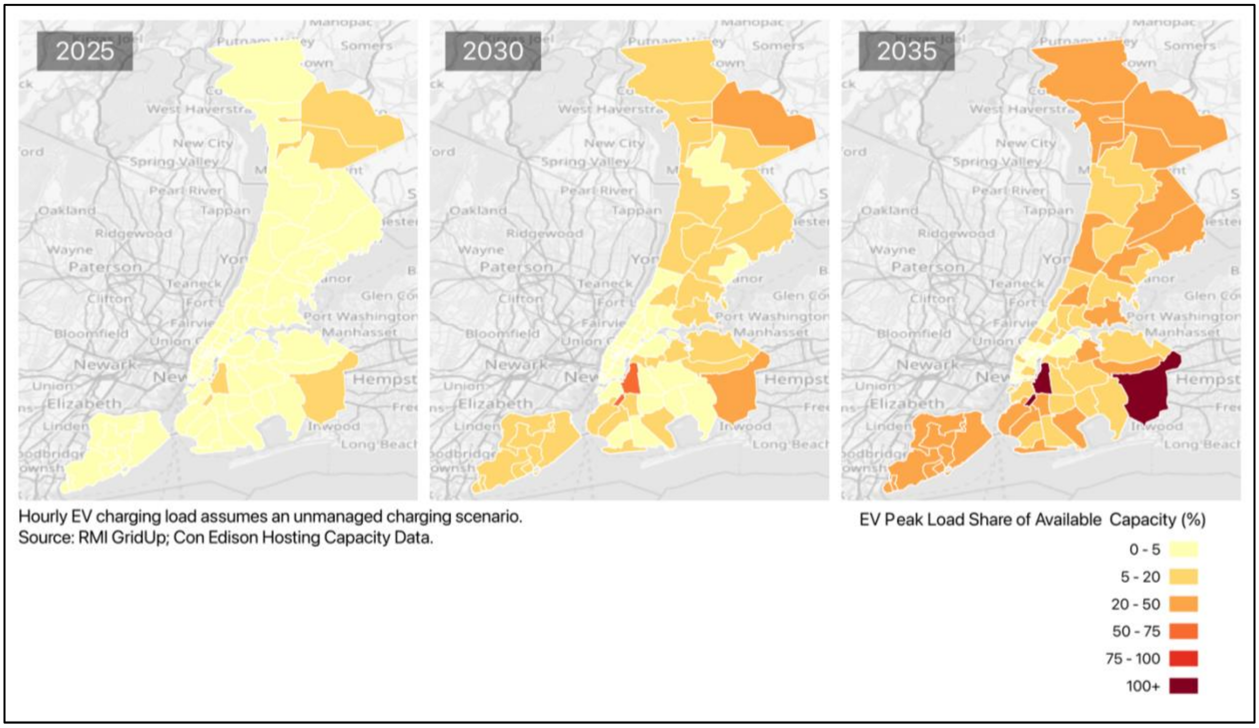
1. We downloaded available hosting capacity data for each utility – by network area for Con Ed and by substation bank plus connected feeders for National Grid. This data provides a snapshot of the currently available capacity (headroom) on different parts of the utilities' distribution systems.
2. This hosting capacity data was then overlaid with GridUp load forecasts for each year between 2025 and 2035, and estimated EV load across each service territory was mapped to either network areas (Con Ed) or substation banks and associated feeders (National Grid). This provides a direct, if simplified, mechanism by which to evaluate the impact of EV load growth on distribution system assets over time.
3. Anticipated EV load growth – and specifically peak load impact[1] – was then compared against the utilities' currently available distribution capacity on an annual basis. This analysis did not assume any new utility capacity deployed or additional load connected, instead holding fixed the headroom available based on the public hosting capacity data available from Con Ed and National Grid.
4. Finally, we calculated the share of currently available capacity that we estimate will be required to support peak EV load in each of the three milestone years (2025, 2030, and 2035).

Note: this assessment does <u>not</u> consider any other, non-EV load growth – such as the significant increase in building electrification load that is anticipated and will be required to comply with state law. This point is important for interpreting the results shown below. As EV load will represent only a <u>portion</u> of total new load, the share of available distribution capacity required to accommodate <u>overall</u> load growth will be higher – often considerably so – than the EV-related share shown in the maps below. For example, based on the 2024 NYISO Gold Book[2,] EV load growth may represent 51 percent of the increase in summer coincident peak demand between 2024 and 2035 across the New York Control Area, although this varies widely based on zone. When accounting for the other, non-EV sources of load growth and their contributions to peak, currently available distribution capacity will be filled even more quickly than our EV-only analysis suggests, further suggesting the need for thoughtful proactive planning.

[1] Peak load impact is based on network area for Con Ed, while for National Grid a system peak of 5:00pm in 2025 was assumed due to data limitations (National Grid UNY – Peak Load Forecast).
[2] Higher Demand Scenario, NYISO Gold Book 2024.

Figures 3 and 4 below highlight the results of our analysis, showing the proportion of currently available distribution capacity on different parts of the utilities' systems that will be needed to meet estimated EV peak load.

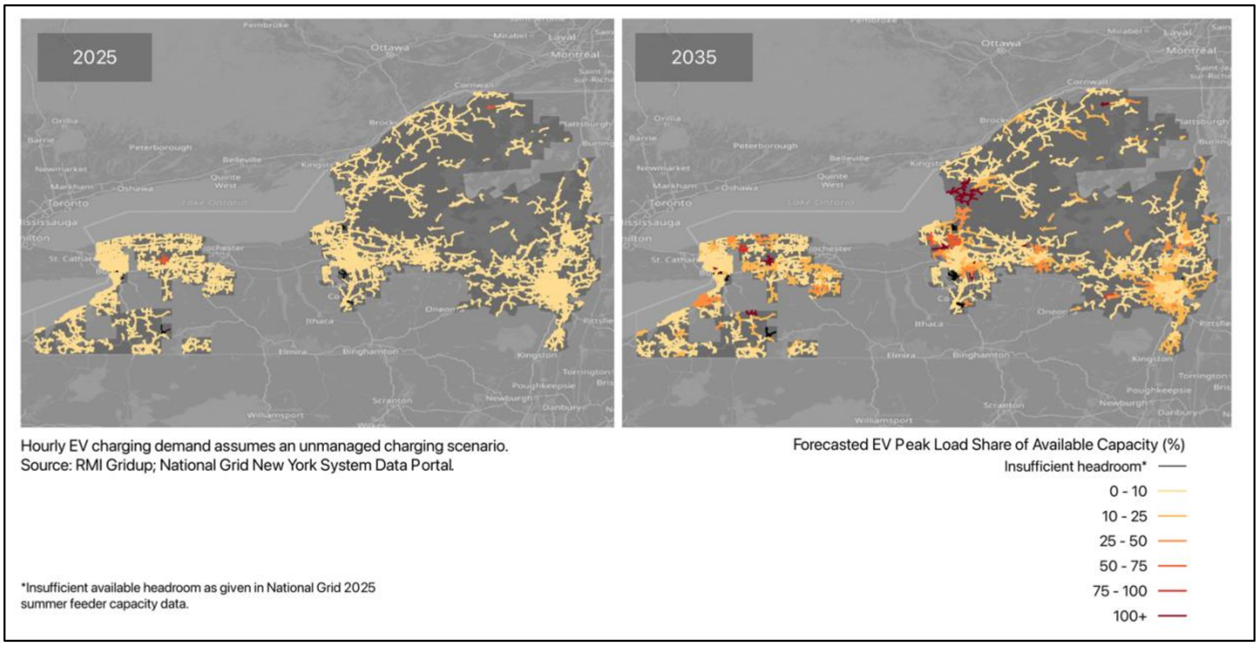
Figure 3: Estimated EV Share of Peak Load by Network Area, Con Ed Service Territory – Unmanaged Charging Scenario



Based on this analysis, three network substations in the Con Ed service territory will have between 20-60 percent of their headroom taken up by EV load by 2030, with a total of 15 substations exceeding 10 percent. By 2035, this share will more than double to over 25 percent for the same 15 networks. In that year, we forecast that two network areas will experience EV load equivalent to or greater than 100 percent of available substation capacity: we estimate that the Jamaica network will see EV load over 155 percent of current substation capacity, while the Williamsburg area will experience over 136 percent.

The areas with the most rapid growth in EV load are Jamaica and parts of northern Queens, South and Central Bronx, and parts of Williamsburg and central Brooklyn.

Figure 4: Estimated EV Share of System Peak Load by Substation Bank, National Grid New York Service Territory – Unmanaged Charging Scenario



By 2030 we expect that seven substation banks in National Grid's service territory will see EV load growth equivalent to 50 percent or more of their currently available capacity. By 2035, 14 substation banks may see EV loads over 100 percent of their current headroom, with four banks over 200 percent; sixteen other substations are expected to see EV load growth at or above 50 percent of their current headroom.

The areas with the most rapid EV load growth and potential for overloads are central Buffalo, the Syracuse and Utica area, West Adams, Western Albany, and northeast of Jamestown.

Successful Load Management Can Meaningfully Reduce EV Contribution to Peak

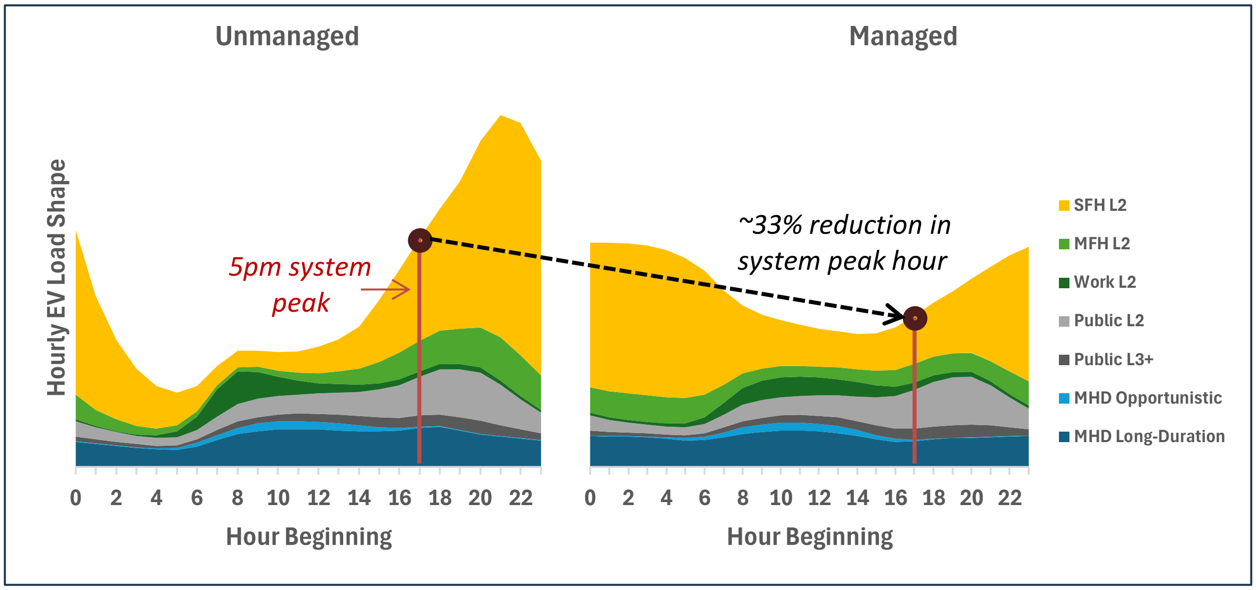
The outputs presented and described above are based on an unmanaged charging scenario from GridUp. This scenario assumes that drivers – whether individuals driving passenger vehicles or commercial operators driving fleet vehicles – begin charging immediately upon arrival at their destination and use the full available charging power until either their battery is fully charged, or their stop is completed (based on underlying driving patterns). In contrast, the managed charging scenario assumes that at long dwell-time locations, drivers utilize the entire duration of that stop to charge and, thus, require less power output.

Figure 5 provides an illustrative comparison of unmanaged and managed charging shapes, based on the overall New York State load profile from GridUp. In this comparison, the managed charging scenario reduces EV contribution to system peak[3] by approximately 33 percent, although the effects will vary in

[3] Assuming system peak at hour beginning 17:00 (2023 ICAP Market Peak Hour, NYISO Gold Book 2024).

specific geographies and based on different hours (e.g., contribution to local network peak vs. total system peak).

Figure 5: Illustrative GridUp Unmanaged vs. Managed Load Shapes – 2035



As shown above, the effect of this load management on EV contribution to local and/or system peaks can be significant. Comparing the unmanaged to managed scenarios in Con Ed territory for 2035, for example (Figure 6, below), highlights that successful EV load management can reduce EV contribution to peak in most network areas by over 20 percent, and by over 30 percent in many. Several specific areas (e.g., Woodrow, Wainwright, Granite Hill) may see reductions in EV contribution to local peaks by upwards of 40 percent if load can successfully be shifted away from those hours.

Figure 6: Reduction in EV Contribution to Network Area Peak Through Managed Charging, Con Ed Territory – 2035

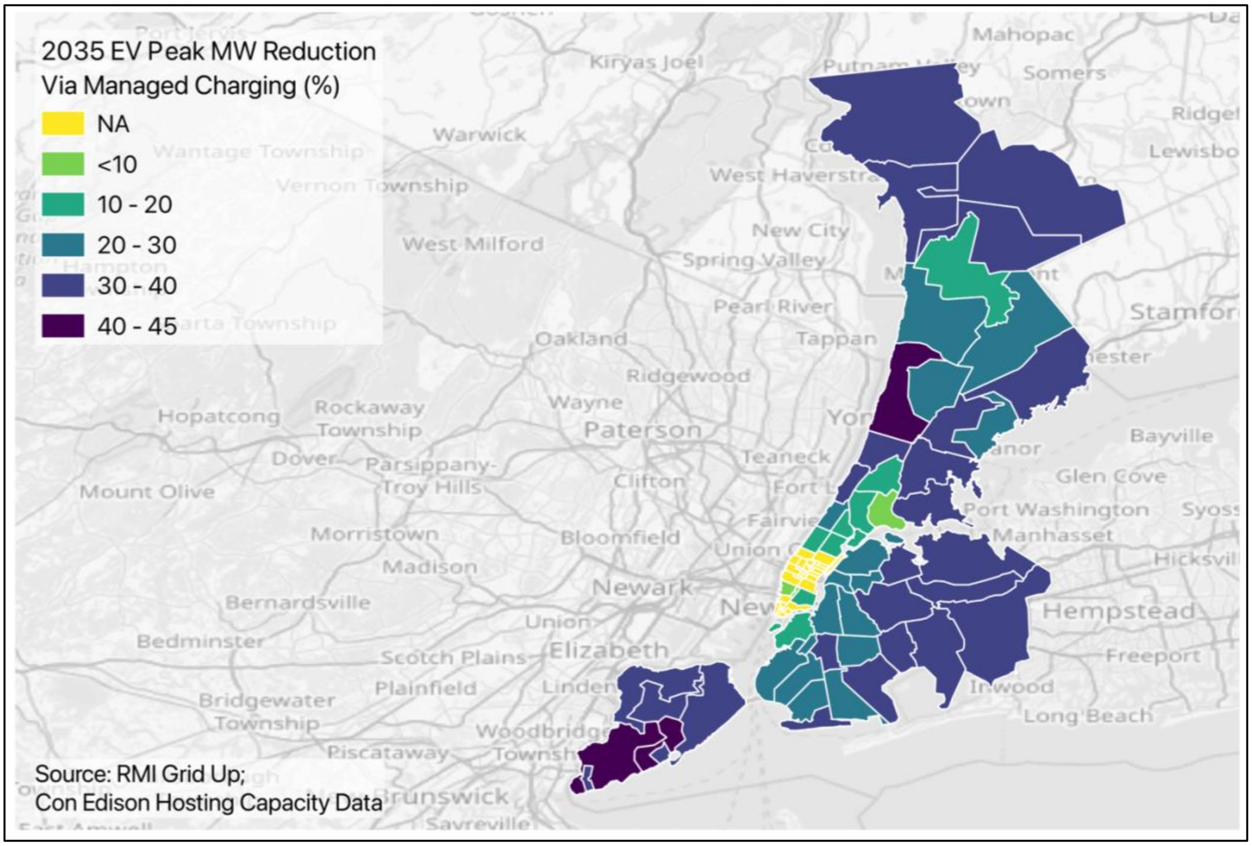


Table 1 compares the unmanaged and managed scenarios based on EV-related share of available headroom taken up by network area for Con Ed, and by substation bank for National Grid. The arrows indicate how successful load management will shift the number of impacted distribution system assets to lower levels of required headroom being allocated to new EV load growth, potentially deferring or reducing the need for new infrastructure investments.

Table 1: Headroom Allocated to EV Load, Unmanaged vs. Managed Scenarios – 2035

	Con Ed (Network Areas)		National Grid (Substation Banks)	
EV Share of Headroom	*Unmanaged*	*Managed*	*Unmanaged*	*Managed*
0 – 20%	43	50	627	708
20- 40%	14	10	101	49
40 – 60%	4	1	29	8
60 – 80%	0	0	6	3
80 – 100%	0	1	2	2
100+%	2	1	14	9

While 100 percent customer participation in managed charging programs is likely unrealistic, the comparison between entirely unmanaged and largely managed (if simplistically) scenarios nonetheless demonstrates the potential value of better charging load optimization. Additionally, more sophisticated forms of managed charging above and beyond the type characterized in this scenario and instead optimized around even more targeted local needs (e.g., more granular distribution asset health or local network conditions) can potentially provide even greater value in terms of both distribution infrastructure planning and investments, and system operations.

Conclusion

The analysis described above highlights the rapid pace at which EV load is expected to grow in New York State and the significant distribution capacity that will be needed to support it. When combined with other forms of load growth, this suggests the necessity for longer-term, more proactive planning of the distribution system to ensure that reliable electric service can be provided to all utility customers. Furthermore, this analysis underscores the key role that various demand-side load management strategies can play in reducing the total amount of new distribution system capacity that will be required. Appropriately planning the distribution system alongside operational and programmatic considerations regarding optimal charging management will be important for right sizing the system. This can and should include both traditional programmatic approaches to managed charging (e.g., time-of-use rates and incentives) and alternative demand-side load-shifting methods, such as various non-wires alternatives and flexible interconnections.

Appendix: Methodological Overview

Analytical Steps

The analysis described above was developed using the following steps.

1. Extract EV load forecasts from the GridUp tool (see detailed GridUp methodology here).
2. Download utility hosting capacity maps from Con Edison and National Grid data portals.
3. Aggregate EV demand forecasts within Con Edison network areas and areas served by National Grid substation banks, identifying MW EV demand for network and system peak hours, respectively.
4. Calculate the annual percentage of available peak headroom utilized by EV charging demand from 2025 to 2035, for Con Edison network areas and National Grid substation banks.
5. Compare these results for both unmanaged and managed charging scenarios.

Simplifying Assumptions

Note that several simplifying assumptions and limitations of this analysis are worth acknowledging.

- The analysis considers summer hosting capacity as available headroom in both territories.
- For Con Edison, the analysis is performed for network area substations and may exclude the impact of radial loads.
- This analysis does not account for pending load connections and any new utility capacity deployed; instead, it holds fixed the network and substation headroom available based on current public data provided by the utilities.
- This analysis does not directly consider the impacts of other, non-EV forms of load growth.