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Examples of State and Utility Actions on Proactive Planning and Investments

August 2026

Jessica Shipley
Thomas S. Benson
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Executive Summary

As states across the nation confront rising electricity demand, significant energy development, grid modernization imperatives, and integration of large new loads, some regulators and utilities are shifting away from reactive, “just-in-time” investment approaches toward more proactive planning and investment frameworks. This report compiles examples of jurisdictional and utility actions that reshape planning processes, cost recovery mechanisms, and performance oversight to anticipate—rather than simply respond to—future grid needs.

Several themes emerge from state actions examined in this report.

First, **legislatures and commissions are directing utilities to proactively upgrade** their distribution and transmission systems, reflecting a shift toward a forward-looking system that aligns planning with state policy goals. For example, the 2023 energy omnibus bill in Minnesota that was codified in state law (§ 216B.2425, subd. 9) required Xcel Energy’s 2023 Integrated Distribution Plan to include a forecast of distribution upgrades needed to comply with various state statutes and a discussion of potential cost allocation options. Similarly, Colorado Senate Bill 24-218 passed in 2024, requiring utility distribution system plans to create sufficient hosting capacity across utility service territories to support the implementation of state and national targets. In Massachusetts, a 2022 bill directed utilities to develop a grid modernization plan and proactively upgrade the distribution and transmission systems and develop a standard of review for the state utility regulator. In New York, utilities were instructed under state law to present investment plans that would fulfill the policy objectives set by legislation in 2019 and augmented in 2020. Regulators are responding to these legislative mandates and creating requirements for utilities. New Jersey’s Board of Public Utilities has advanced Integrated Distribution and DER System Planning and Proactive System Upgrade Plans, requiring utilities to assess grid readiness, forecast distributed energy resource (DER) and load growth, and propose cost-effective solutions to increase hosting capacity and grid flexibility.

Second, states are **establishing new or augmenting existing planning frameworks to address proactive planning**. California, Colorado, and Minnesota are augmenting existing planning processes, whereas New York, Massachusetts, and New Jersey are creating new processes for identifying and proposing proactive investments. Processes often feature multi-year horizons, biannual or annual compliance reporting, structured opportunities for stakeholder engagement, and in some cases, emphasis on collaboration among utilities, regulators, and stakeholders. New York utilities have developed a Proactive Planning Framework Methodology and will file Proactive Planning Study Reports that identifies grid needs driven by electrification for which proactive investment would improve overall cost-effectiveness, minimize ratepayer impact, and support policy outcomes. Massachusetts utilities developed a proposal for a Long-Term System Planning Process Framework, which is the proactive system-level process to identify incremental investments to accommodate load growth and accommodate future generation growth. In Minnesota, the Commission established a Framework for Distribution Grid Upgrades and Xcel Energy is filing Proactive Grid Upgrade Proposals as part of Integrated Distribution System Plans. New Jersey’s proposed Proactive System Upgrade Plans are designed to provide transparency, guide utilities in requesting approval for infrastructure investments, and facilitate stakeholder engagement through regular updates and structured reporting.

Third, **methodological improvements in planning**, such as increasing the granularity and rigor of load forecasts and analyzing different forecast scenarios, are recurring areas of

stakeholder focus across jurisdictions. California has introduced a new “pending loads” category in distribution system planning that includes more granular bottom-up forecasts of likely or known new loads. California has developed a structured process for when and how pending loads are included in forecasts and scenario planning, and how single investment plans can be derived from scenarios analysis. In New York, utilities identified urgent upgrade projects needed to meet policy goals. As part of the Proactive Planning Framework, New York utilities are also charged with identifying “hotspots” where significant loads from electrified transportation are likely to emerge. Detailed data sources associated with these hotspots and potential proactive investments must be identified as part of the New York Proactive Planning Framework Methodology. In Massachusetts, proactive hosting capacity investments are being proposed in locations where additional hosting capacity is needed to accommodate system growth. New Jersey’s emerging approach emphasizes baseline system assessments, scenario analysis for DER adoption, and a DER registry that features common data fields and definitions across Electric Distribution Companies (EDCs).

Fourth, states are actively investigating **innovative cost-recovery mechanisms** to support accelerated electrification and grid modernization, while balancing consumer advocates’ concerns about the ratepayer financial risks of premature investments. In Colorado, Senate Bill 24-218 required the Public Utility Commission to develop a cost-recovery mechanism so utilities can recover costs for distribution activities that strategically advance the achievement of state and national targets. In Massachusetts, utility companies proposed a long-term system planning tariff, which allows recovery of costs associated with Proactive Hosting Capacity Investments through a Proactive Hosting Capacity Fee that reflects the interconnecting customers’ pro rata share of the costs of proactive hosting capacity upgrades. Minnesota has a similar approach, with a proactive cost-share window during which interconnecting customers pay a portion of proactive investments through a cost-share fee. In Southern California Edison’s general rate case, the Commission rejected calls for a balancing account to track and cover transportation electrification investments but authorized a memorandum account to track and review grid-readiness expenditures.

Fifth, **performance metrics and reporting requirements** are being developed to ensure transparency and accountability for proactive investments. New York utilities are required to file quarterly update reports that include status updates on urgent and proactive upgrade projects. California utilities are required to track and report up-to-date known load projects to the California Energy Commission as part of the utilities’ Grid Needs Assessments. Massachusetts requires biannual compliance reports on Electric System Modernization Plans with standardized performance metrics and annual reporting on electrification loads. In New Jersey, the proposed Proactive System Upgrade Plans include requirements for regular reporting on grid modernization progress, DER deployment, and stakeholder engagement.

Overall, these developments signify a growing recognition among state regulators, utilities, and stakeholders that proactive planning—supported by clear definitions, consistent and transparent methodologies, regular reporting, and innovative cost recovery mechanisms—is a tool that can be used to address the scale and urgency of contemporary grid needs.

Acronyms

BE	Beneficial Electrification
BPU	Board of Public Utilities
CEC	California Energy Commission
CGPP	Coordinated Grid Planning Process
CIP	Capital Investment Project
CLCPA	Climate Leadership and Community Protection Act
CPUC	California Public Utilities Commission
DER	distributed energy resource
DG	distributed generation
DPEP	Distribution planning and Execution Process
DPP	Distribution Planning Process
DPS	Department of Public Service
DPU	Department of Public Utilities
DSP	distribution system planning
EDC	Electric Distribution Company
ESMP	Electric Sector Modernization Plan
EU	European Union
EV	electric vehicle
EVSE	electric vehicle supply equipment
GMAC	Grid Modernization Adjustment Clause
GRC	general rate case
I&A	Inputs & Assumptions
IDP	Integrated Distribution Plan
IEPR	Integrated Energy Policy Report
IOU	investor-owned utilities
LTSP	Long-Term System Planning Process
MHDV	medium- and heavy-duty vehicle
MW	megawatt
NRDC	Natural Resources Defense Council
NYCRR	New York Codes, Rules and Regulations
NYSEG	New York State Electric and Gas
NYSERDA	New York State Energy Research and Development Authority
PG&E	Pacific Gas & Electric
PHC	Proactive Hosting Capacity
PHCI	Proactive Hosting Capacity Investment
PSC	Public Service Commission

PSUP	Proactive System Upgrade Plan
PUC	Public Utilities Commission
RGE	Rochester Gas and Electric
SB	Senate Bill
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SWEEP	Southwest Energy Efficiency Project
TE	transportation electrification
TEGR	Transportation Electrification Grid Readiness
TEPP	Transportation Electrification Proactive Planning

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1.0 Introduction

The U.S. electric grid is undergoing a period of change. Increased electrification, the rapid emergence of large new loads such as data centers and advanced manufacturing facilities, and the increasing frequency of extreme weather events are collectively placing unprecedented demands on transmission and distribution systems. Traditional planning paradigms rooted in reactive responses to identified reliability needs or interconnection requests are increasingly viewed as insufficient to address the pace, scale, and complexity of these emerging challenges.

In response, some states are exploring and adopting proactive planning and investment approaches. These approaches seek to anticipate future system needs, evaluate a broader range of benefits, integrate distribution and transmission planning more closely with state policy objectives, and design cost recovery and oversight mechanisms that align utility incentives with long-term planning outcomes. The adoption of proactive planning is still nascent, but useful examples are beginning to emerge.

This report presents a curated set of examples of state and utility actions on proactive planning and investments. It is intended to support regulators, utilities, consumer advocates, and other stakeholders by:

- Documenting current practices and recent regulatory developments at the state level
- Highlighting proactive definitions, frameworks, and rationales that states are using to justify and structure forward-looking planning
- Identifying new or modified methodologies emerging in state proceedings and utility plans
- Summarizing the issues and concerns raised by parties throughout these proceedings
- Providing references and links to source materials for further investigation.

The report draws on a range of state-level proceedings, hearing officer memoranda, utility filings, and stakeholder comments, as well as an international case (the European Union [EU]). The examples are drawn from jurisdictions at varying stages of developing and implementing proactive approaches.

This report is organized by the originating entity (e.g., state, EU, etc.), with each example containing similar information, such as background, proactive definitions or frameworks, methodological developments, and a summary of issues or concerns raised. **By compiling these examples and resources in a single report, we aim to facilitate cross-state learning and inform ongoing efforts to align grid planning and investment with evolving policy, technology, and reliability demands.**

This report does not make recommendations on best practices; the authors intend to separately publish a summary of options in a regulatory framework that draws on the practices described.

2.0 Context

Across the states discussed in the report, the impetus for more proactive grid approaches varies based on the policy goals and needs of each state. The report, in which we review utility filings, dockets, party comments, and Commission decisions and orders related to proactive planning and investments, points to rising electricity demand driven by electrification, a desire to increase generation interconnecting at the distribution level, and the rapid growth of large new loads (such as data centers and advanced manufacturing), that is putting new pressure on existing grids. Some utilities and regulators find existing processes insufficient to meet their states' needs. However, others are embracing new practices. Table 1 summarizes key drivers for proactive approaches in the states (and countries) described in this report. Proactive planning and investment issues arise in a variety of docket types, including distribution system plans or dockets dedicated to distributed energy resources (DERs), general rate cases, transportation electrification plans, grid modernization proceedings, construction work in progress authorizations, and Commission-directed investigations. These dockets are predominantly initiated following legislative mandates or in response to utility proposals or filings.

Table 1. States and Governing Bodies Covered in This Report and Their Primary Drivers for Proactive Action

STATE	PRIMARY DRIVER(S) FOR PROACTIVE APPROACHES
California	Rapid load growth—especially from transportation electrification—and high DER adoption are leading to energization delays and long lead times for distribution upgrades.
Colorado	Increasing difficulty connecting new or expanded load due to distribution capacity constraints, and the need for forecasting to be better aligned with state policies.
Massachusetts	Statutory requirement directing utilities to proactively upgrade distribution systems to meet state policy goals.
Minnesota	Need to enable customer adoption of DERs and electrification, reduce or eliminate interconnection wait times, avoid construction bottlenecks, and achieve lifecycle cost efficiencies.
New York	Electrification mandates in law create large, location-specific new loads, especially from medium/heavy duty vehicle charging.
New Jersey	Modernization of the grid to accommodate growing DER and electrification demands while ensuring cost-effective, transparent, and forward-looking planning that supports reliability and ratepayer affordability.
EU	Need to meet EU energy policy goals; widespread aging infrastructure; risk of multiyear delays in connecting new generation; and the need for forward-looking, long-lead transmission and distribution investments based on future, not current, connection requests.

The following sections provide summaries of the types of proposals related to proactive planning and investment, frameworks or new methodologies being discussed, and issues and concerns raised by key actors, including Commissioners and staff where available. These examples are intended to be representative but not exhaustive of all relevant proposals, dockets, and filings.

3.0 California

Three proceedings in California that address or support proactive investments are described in this section.

- California Proceeding to Modernize the Electric Grid for a High Distributed Energy Resource Future (Proceeding R2106017).
- California Transportation Electrification Proactive Planning (TEPP) (Proceeding No. R.23 12-008).
- Southern California Edison 2025 General Rate Case Supplemental Load Growth Forecast Methodology (A2305010).

3.1 California Proceeding to Modernize the Electric Grid for a High Distributed Energy Resource Future ([Proceeding R2106017](#))

3.1.1 Background

- In 2021, the California Public Utilities Commission (CPUC) issued Order Instituting Rulemaking to Modernize the Electric Grid for a High DER Future with the purpose to “prepare the electric grid for a high number of distributed energy resources, including those specific to transportation.” They expect continuing DER growth in the state, “especially due to policies and programs driving transportation electrification and associated DERs.”¹
- With respect to grid modernization, the order aims to 1) “enable swift evolution of grid capabilities and operations to integrate solar, storage, electric vehicles (EV)/electric vehicle supply equipment (EVSE) and other DERs to meet the state’s 100% clean energy goals;” 2) “improve distribution planning, including charging infrastructure forecasting to support cost effective and widespread (transportation electrification);” and 3) “optimize grid infrastructure investments by facilitating community input about planned developments, DER siting plans, and resiliency needs.”²
- The proceeding contains three tracks: (1) Distribution Planning and Execution Process and Data Improvements (two phases); (2) Distribution Systems Operational Needs and System Operator Roles and Responsibilities; and (3) Smart Inverter Operationalization and Grid Modernization Planning (two phases).³
- In May 2023, an Electrification Impact Study completed for the CPUC published bottom-up load forecasting and system-level electrification impacts and cost estimates. The study documented the potential impacts of high DER (including electrification) adoption on the distribution grid.⁴
- California has experienced an increase in load growth that, coupled with issues in the Distribution Planning and Execution Process (DPEP), led to customer energization delays and long lead times for energization. Two California state bills (Senate Bill [SB] 410 and

¹ California Public Utilities Commission (CPUC). “Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future.” July 2, 2021.

<https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M390/K664/390664433.PDF>.

² Ibid.

³ CPUC. “Distribution Planning.” Accessed June 12, 2026. <https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/infrastructure/distribution-planning>.

Assembly Bill 50), signed into law in October 2023, aim to address these delays. Assembly Bill 50 required that “1) each utility evaluate and update its existing [DPPs] to improve the accuracy of the projected demand and ensure timely energization, and each utility must have annual meetings with interested stakeholders to discuss issues related to distribution planning.”⁵

- In March 2024, CPUC’s Energy Division staff released a proposal for improving the Distribution Planning Process (DPP).⁶ Staff noted that historic change in load growth (including from transportation electrification) plus a conservative and reactive DPP means that utilities have fallen behind on distribution capacity work and that is leading to energization delays and long lead times. Staff proposal for an improved DPP suggested that the utilities should develop a “pending loads” category in their distribution planning, which is less certain than a “known load,” but more certain than economic disaggregation of California Energy Commission’s (CEC’s) Integrated Energy Policy Report (IEPR) forecast.
- In October 2024, CPUC issued a decision (24-10-030) adopting improvements to the DPEP.⁷ This decision was informed by 2 years of engagement and review with utilities to determine what near-term improvements to activities such as investment planning, prioritization, execution, and cost recovery could be made to effectively and efficiently execute infrastructure projects.
- Two requirements of decision 24-10-030 with relevance to proactive planning are 1) a requirement for utilities to hold a Pending Loads Implementation Workshop and submit a Workshop Report and 2) a requirement for the utilities to file the Electrification Impact Study Part 2 and include within that an assessment of a load flexibility distribution planning process.
- In December 2025, the CPUC adopted a resolution to approve with modifications the proposals of the investor-owned utilities (IOUs) to establish a pending loads category in the distribution system planning process.⁸
- Also in December 2025, the CPUC adopted a resolution to establish a scenario planning framework within the DPP.⁹ In this resolution, they highlighted that the “purpose of pending loads is to improve forecast certainty in the medium-term of the forecast to support proactive investments with the goal of meeting electric demand growth while balancing the risk of overinvestment.”
- In January 2026, Pacific Gas & Electric (PG&E), San Diego Gas & Electric (SDG&E), and Southern California Edison (SCE) each filed their Electrification Impact Study Part 2 Final Reports.
- A timeline of proactive developments in California is shown in Figure 1.

⁵ Kevala. “CPUC Electrification Impacts Study Part 1: Bottom-Up Load Forecasting and System-Level Electrification Impacts Cost Estimates.” May 9, 2023. <https://www.kevala.com/resources/electrification-impacts-study-part-1>.

⁶ CPUC. “Staff Proposal for the High DER Proceeding.” March 13, 2024. <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M527/K221/527221491.PDF>.

⁷ CPUC. “Decision Adopting Improvements to Distribution Planning and Project Execution Process, Distribution Resource Planning Data Portals, and Integration Capacity Analysis Maps.” October 23, 2024. <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M544/K154/544154869.PDF>.

⁸ CPUC. “Resolution E-5413.” December 18, 2025. <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M592/K318/592318785.PDF>.

⁹ CPUC. “Resolution E-5414.” December 18, 2025. <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M592/K455/592455565.PDF>.

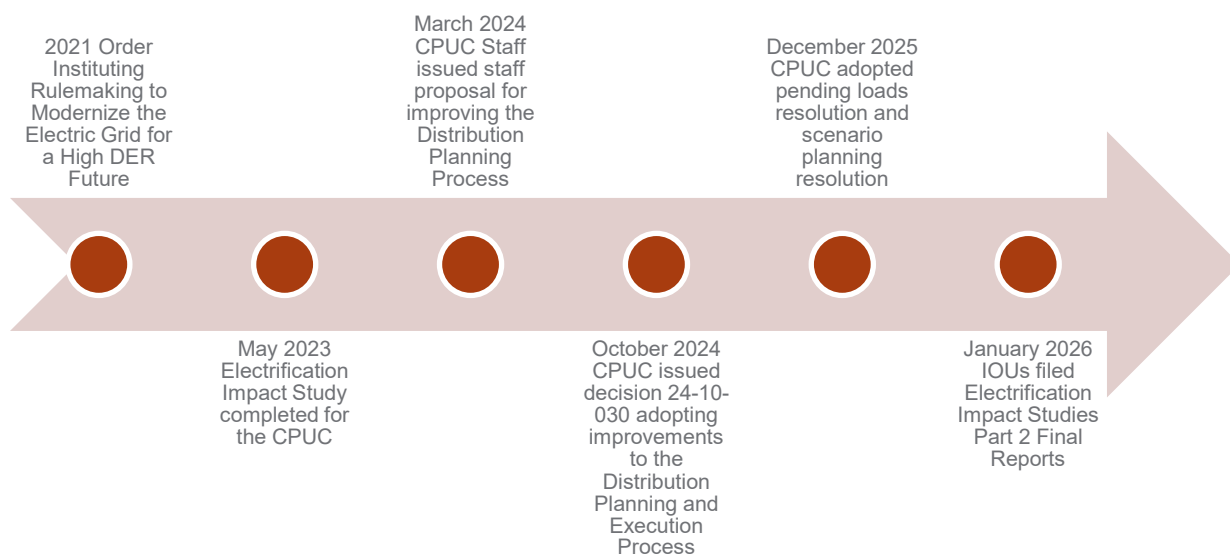


Figure 1. Timeline of Proactive Developments in California (2021–2026)

3.1.2 Proactive Definitions, Frameworks, or Rationales

- CPUC staff provide some definitions and rationales in the 2024 Staff Proposal. The “new paradigm” of distribution planning must “become more proactive by anticipating new loads and being prepared to serve them without lengthy distribution upgrades.”¹⁰
- For CPUC staff, “a desired outcome of more proactive distribution planning and execution would be that fewer customer requests are waiting for long-lead-time distribution upgrades before they can be served.” Indeed, the “historic change in load growth” occurring in California is cited as the rationale for a “more robust and forward-looking distribution planning and execution process.”¹¹
- Rather than adopting a new framework or process for analyzing and approving proactive investments, the CPUC adopted multiple updates to the requirements of the pre-existing DPEP to incorporate proactive elements and address party concerns. Aspects of these updates are discussed in Section 3.1.3.
 - The CPUC staff proposal states that “Pending Loads are a proposed category of load that is less certain than a ‘known load,’ also known as a customer request for service, but more certain than economic disaggregation of the IEPR [integrated energy policy report] forecast based on trends. The purpose of creating this category is to increase utility awareness of where load will likely appear in the mid-term years of the DPP without known loads ... The goal of the Pending Loads category should be to estimate future load growth from any source outside of known loads in a way that balances the reliability of current information with the importance of proactive planning and investment.”¹²

¹⁰ CPUC. “Staff Proposal for the High DER Proceeding.” March 13, 2024.
<https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M527/K221/527221491.PDF>.

¹¹ Ibid.

¹² Ibid.

- The staff proposal goes on to mention that “implementation of the Pending Loads category would include at a minimum, estimates of likely load growth tied to specific circuits or substation banks in the mid-term (roughly defined as years 2 to 5) outside of existing Known Loads. Utilities can produce these estimates based on any information gathered from coordination and engagement efforts with customers, especially concerning electrification plans, and other relevant and reliable sources. Pending loads may be used to inform upgrades to primary distribution infrastructure including new or upgraded circuits, new or upgraded substation banks and substations.”¹³

3.1.3 New or Modified Planning, Cost Allocation, or Cost Recovery Methodologies

- The Staff Proposal (March 2024) suggested extending the planning horizon to 10 years (from 5 years currently) in the DPP. It argued for allowing utilities to use bottom-up, known load data in load forecasts even if that exceeds the CEC’s forecasted growth. It proposes a new concept of “pending loads,” which are loads that are reasonably expected but not are yet part of formal customer applications. Many questions about the practical use of pending loads are posed. Staff also propose the use of scenario planning to improve load forecasts and propose the use of more flexible inputs for utilities to request distribution capacity costs in their general rate case (GRC).
- In comments from May 2024, SCE proposes that the CPUC allow IOUs to apply for incremental funding between GRCs and, in doing so, allow the utilities to provide a full showing of the additional investment need, including a full justification, as opposed to the current mechanism, which provides this after expenditures have been made.¹⁴ SCE also recommends that the CPUC adopt a new framework for mid-cycle funding that allows upfront per se reasonableness based on compliance with detailed rules and guidelines, along the lines of what is already done for energy procurement costs.
- In the October 2024 Order (24-10-030), the CPUC adopted improvements related to DPEP, distribution resource planning data portals, and integration of capacity analysis maps. In this decision, the CPUC referenced the transportation electrification rulemaking that is developing the TEPP “framework with the objective of creating unified inputs and assumptions for planning processes.” They added that the inputs and assumptions may include “electricity demand forecasts, which will be critical for scenario development and the pending loads category of the [DPP]” and that they recognize “the importance of coordination between these two proceedings.”¹⁵
- In the October 2024 Order, utilities are directed to 1) use reliable bottom-up data to estimate load growth in a given year; 2) collaborate with the CPUC and CEC to develop proposals to improve the method for setting caps on load growth from the IEPR; 3) extend the distribution planning forecast horizon to a minimum of 13 years and utilities’ planning horizons to 10 years but maintain the 3-year minimum horizon for line section analysis; 4) implement the use of scenario planning in the DPEP in the 2025–2026 DPP cycle; 5) improve disaggregation methodologies for implementation in the 2026–2027 DPP cycle; 6) create a pending loads category in the DPP; 7) submit separate advice letters to propose

¹³ Ibid.

¹⁴ CPUC. “Comments filed by Southern California Edison Company on 5/28/2024 Conf#206933.” May 30, 2024. <http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=532677198>.

¹⁵ CPUC. “Decision Adopting Improvements to Distribution Planning and Project Execution Process, Distribution Resource Planning Data Portals, and Integration Capacity Analysis Maps.” October 23, 2024. <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M544/K154/544154869.PDF>.

project prioritization methods, methods for integrating planning, and bridging strategies to accommodate energization requests that trigger distribution capacity work; 7) prepare a load flexibility planning process assessment and propose how to integrate it into the DPEP; 8) submit an annual community engagement plan to address equity in the DPEP; 9) eliminate distribution investment deferral solicitations and focus on improving transparency of the DPEP; 10) include metrics to evaluate equity in utility distribution plan reporting; and 11) track and report all known load projects to the CEC in a way that it is possible to track which known load become actual projects and the timeframe in which they do so.¹⁶

- The DPEP is a 10-step process that can be divided into the five-step DPP (where utilities forecast future load on the distribution system and determine when and where upgrades will be needed) and the five-step Execution Process in which solutions are designed, prioritized, and constructed. The general process is as follows: 1) historical load profile review; 2) forecast adoption; 3) load and DER disaggregation; 4) grid need identification; 5) solution development; 6) project prioritization in workplan; 7) project scoping; 8) planning, designing, and estimating; 9) permitting, sourcing, and release; and 10) construction.¹⁷
- The December 2025 Resolution on pending loads adopted a new uniform framework that allows for individual differences in the sources of input data to identify the pending load projects and hot spots,¹⁸ which are geographic areas with high load growth and capacity constraints. Table 2 summarizes the categories of pending loads laid out in the High DER Proceeding and how they can be used in scenario planning.

Table 2. Categories of Pending Loads in California High DER Proceeding. Source: December 2025 Resolution E-5413 in SCE AL 5567-E, SDG&E AL 4676-E, PG&E AL 7630-E/JT8¹⁹

Pending Load Category	Description	Use in Base Scenario
A	High confidence projects and are based on detailed customer plans	Can Exceed IEPR
B1	Medium confidence projects based on less detailed customer plans	Can Exceed IEPR
B2	Studies based on customer-based data inputs, and utility analysis-based compliance obligations.	Capped at IEPR except for hot spots
C	Preliminary customer plans and trends and non-customer-based studies	Capped at IEPR always

¹⁶ Ibid.

¹⁷ CPUC. "Proposed Decision of Commissioner Houck." October 17, 2024. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/infrastructure/distribution-planning/highder_t1p1_pdrev1.pdf.

¹⁸ CPUC. "Resolution E-5413." December 18, 2025. <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M592/K318/592318785.PDF>.

¹⁹ Ibid.

- The December 2025 Resolution on scenario planning adopted a uniform framework that allows for individual differences in the details of implementation for each IOUs initial implementation of scenario planning.²⁰ The framework consists of three scenarios: 1) Low, 2) Base, and 3) High, based on a range of factors, including the categories of pending loads included, the use of pending loads, and changes in assumptions. Each category of pending loads is or is not incorporated into each scenario in the scenario planning framework. Table 3 describes how categories of pending loads are included in planning scenarios.

Table 3. How Categories of Pending Loads are included in Planning Scenarios. Source: December 2025 Resolution E-5413 in SCE AL 5567-E, SDG&E AL 4676-E, PG&E AL 7630-E/JT8²¹

Pending Load Category	Description	Low Scenario	Base Scenario	High Scenario
A	High Confidence, Customer Based Projects	Included Can Exceed IEPR	Included Can Exceed IEPR	Included Can Exceed IEPR
B1	Medium Confidence, Customer Based Projects	Excluded	Included Can Exceed IEPR	Included Can Exceed IEPR
B2	Bottom-Up Study	Excluded	Included Capped at IEPR except for hot spots	Included Can Exceed IEPR
C	Low Confidence, Customer Based Projects and Studies	Excluded	Included Capped at IEPR always	Included Capped at IEPR except for hot spots

- An early concern about scenario planning surrounded how to incorporate the results of multiple scenario analyses into a single investment plan. In the December 2025 Resolution on scenario planning, the CPUC affirmed that one of the goals for scenario planning is to “prepare the distribution grid for load growth through a set of planned investments that meets near term and long-term needs and includes least regrets proactive investments.” The resolution adopted a decision logic, as proposed by SCE, to create a single set of planned investments. Table 4 illustrates single-investment planning strategies and distribution planning outcomes under base and high growth scenarios.

²⁰ CPUC. “Resolution E-5414.” December 18, 2025.
<https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M592/K455/592455565.PDF>.

²¹ CPUC. “Resolution E-5413.” December 18, 2025.
<https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M592/K318/592318785.PDF>.

Table 4. Illustrative Single-Investment Planning Strategies and Distribution Planning Outcomes Under Base and High Growth Scenarios (adapted from the CPUC High DER proceeding)²²

Ex.	Base Scenario Solution and High Scenario Solution	Solution for Single Investment Plan	Outcome for distribution planning
1	Base: No grid need High: Sub-circuit solution	Reassess next planning cycle	• Status quo
2	Base: No grid need High: New circuit or more	Potentially plan partial construction • If grid need is within year 1-5, plan to build out to first switch • If grid need is within years 6-10, reassess next planning cycle	• Reduces lead time of future new circuit(s) by ~1-2 years • Built assets could be repurposed for other load growth-driven needs and increased operational flexibility if original needs do not materialize
3	Base: New Circuit(s) High: Base+ additional New Circuit(s)	Plan to build new circuit(s) to address Base need plus additional construction: • If location of the High Scenario's load growth is known, plan new circuit mainline toward load • Otherwise plan out to first switch	• Reduces lead time of future new circuit(s) by ~1-2 years • Built assets could be repurposed for other load growth-driven needs and increased operational flexibility if original needs do not materialize
4	Base: New Circuit(s) High: Base+ additional New Circuit(s) + Substation Capacity upgrade	Solution for circuits above, plus potential substation work: • If substation utilization is approximately 60-90%, design and procure equipment for substation capacity upgrade • If substation utilization is more than 90%, plan to build substation capacity upgrade	• Substation capacity upgrade lead time ~4 years • Design and procurement reduce lead time of substation capacity upgrade by ~1 year • Built assets could be repurposed for other load growth-driven needs and increased operational flexibility if original needs do not materialize
5	Base: New Circuit(s) High: Base+ additional New Circuit(s) + Substation Capacity Upgrade + New Substation	Circuit and substation solution above, plus potential land development • Identify potential locations for new substation • If land highly constrained, may consider planning to acquire land	• Advanced planning for land procurement

²² Ibid.

- In PG&E’s Electrification Impact Study Part 2 Final Report, they stated that to mitigate similar risks in future planning cycles like those during the COVID-19 pandemic (e.g., supply chain disruptions, procurement challenges), they would implement a “proactive bulk procurement strategy.” This involves “securing long-lead materials in advance of engineering milestones.”²³

3.1.4 Summary of Issues or Concerns Raised

- The issues in this docket regarding proactive planning can be summarized as a tension between proactive planning and investing in distribution system upgrades to make sure new loads are energized in a timely manner and managing any potential ratepayer impacts of increased investments. Load is growing fast and distribution investments have not kept pace. There are concerns about being able to keep up with transportation electrification.²⁴
- All commenting parties supported the recommendation that utilities be able to modify the IEPR load forecasts with bottom-up data on additional loads. There was some disagreement about how to define bottom-up data, with some parties requesting a clear definition of bottom-up data as known load data provided to utilities through energizing applications and others supporting no fixed definition. Others supported using projected load growth needed to achieve regulatory compliance on a basis for bottom-up forecasts. Some parties encouraged the Commission to ensure the data is transparent and published for stakeholder review.
- Regarding pending loads, the staff asks how to de-risk those loads, where and when they should be used, how to implement the concept, and how it should interact with the CEC’s forecast. PG&E argues that utilities need authorization to use pending loads to justify project investments in the GRC.²⁵
- Utilities and the staff proposal raise the need for a mechanism to enable incremental cost recovery between GRC authorizations, pursuant to requirements in SB 410.²⁶ Southern California Edison has commented that the existing mechanism for cost recovery between rate cases is flawed because it does not provide for “upfront reasonableness determination of a utility’s planned long-term investments.” SB 410 required the Commission to authorize a cost-recovery mechanism to fund energization costs, including upgrades to distribution capacity. The staff proposed, and the Commission adopted, an approach that allows utilities greater flexibility in requesting distribution capacity costs in GRCs, specifying that utilities may use the results of the annual DPP as a basis for requesting forecasted distribution upgrade costs within the GRC. Outside of this proceeding, the Commission approved, with modifications, applications from both PG&E and SDG&E for an SB 410 ratemaking

²³ CPUC. “Pacific Gas and Electric Company’s (U 39 E) Electrification Impacts Study Part 2 Report.” January 28, 2026. <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M596/K907/596907812.PDF>.

²⁴ CPUC. “Staff Proposal for the High DER Proceeding.” March 13, 2024. <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M527/K221/527221491.PDF>.

²⁵ Ibid.

²⁶ SB 410 allows California utilities to recover costs between general rate cases, subject to prudence review by the CPUC.

mechanism.^{27,28} SCE did not apply for this mechanism, likely because their rate case fell after the passage of SB 410, so they did not need an interim mechanism.

3.2 California Transportation Electrification Proactive Planning ([Proceeding No. R.23-12-008](#))

3.2.1 Background

- In December 2023, the CPUC issued an order instituting rulemaking R23-12-008 regarding Transportation Electrification Policy and Infrastructure.²⁹ This proceeding is focused on improving transportation electrification specific data, assumptions, and analysis that are ultimately inputs into existing processes (e.g. DPP, Transmission Planning Process) overseen by other proceedings.
- In April 2024, the CPUC issued a scoping memo and ruling, stating that “this proceeding is the venue where the Commission will comprehensively assess the needs for transportation electrification policy and infrastructure.” One of the issues the proceeding will focus on is a TEPP Framework.³⁰

3.2.2 Proactive Definitions, Frameworks, or Rationales

- The R.23-12-008 scoping memo defines proactive planning as long-horizon, interagency, data-driven grid planning that is focused on inputs and assumptions rather than approving specific projects, with the explicit purpose of preventing lead-time mismatches from blocking electrification goals.³¹
- R.23-12-008 is focused on improving transportation electrification-specific data, assumptions, and analysis that can ultimately be inputs into existing electric grid planning processes (e.g., the Distribution Planning Process and Transmission Planning Process) being developed in other proceedings at the Commission.³²

3.2.3 New or Modified Methodologies

- In the April 2024 scoping memo, the CPUC highlights that the proactive planning framework includes an initial focus on “zero emissions freight infrastructure planning because of 1) significant load growth anticipated with medium-duty and heavy-duty charging and 2) its likely impact on electric infrastructure.” Proactive planning for transportation electrification is essential because of the “long lead-time” required to

²⁷ CPUC. “Application of Pacific Gas and Electric Company for Authority, Among Other Things, to Increase Rates and Charges for Electric and Gas Service.” July 16, 2024.

<https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M536/K025/536025604.PDF>.

²⁸ CPUC. “Application of San Diego Gas & Electric Company (U902E) for Authority to Establish a Rate-making Mechanism for Energization Projects Pursuant to Senate Bill 410.” November 7, 2025.

<https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M586/K499/586499719.PDF>.

²⁹ CPUC. “Order Instituting Rulemaking Regarding Transportation Electrification Policy and Infrastructure.” December 20, 2023.

<https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M521/K872/521872957.PDF>.

³⁰ CPUC. “Assigned Commissioner’s Scoping Memo and Ruling.” April 12, 2024.

<https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M529/K525/529525879.PDF>.

³¹ Ibid.

³² Ibid.

develop transmission and distribution infrastructure and because it can “reduce the risk of limited grid infrastructure impeding the success of electrification” in transportation.³³

- In the April 2024 scoping memo, priority actions for TEPP included 1) development of transportation electrification modeling inputs and assumptions (I&A) for use in existing grid infrastructure planning and cost recovery processes; 2) development of a corridor designation tool that can be used to identify priority corridor segments for proactive transportation electrification planning; 3) adoption of a process for ongoing reassessment of transportation electrification planning priorities; and 4) the need for a study of priority areas, beginning with identified highway corridors, to identify barriers to transportation electrification.³⁴
- In August 2025, drafts of the TEPP: Modeling I&A Report and Corridor Disaggregation Methodology were released. Energy Division staff hired Guidehouse to conduct the analysis and develop the methodologies. These documents laid out methods to “inform size, timing, and location of corridor-based transportation electrification (TE) charging in California through a collaborative effort with the CEC.”³⁵
 - TEPP methodology would “provide localized insights to identify the timing, location, and size of expected transportation electrification (TE) load growth along highway corridors in California for use in existing planning and cost recovery processes.” Additionally, the methodology would “allow for consistent forecasting and scenario building across existing planning and cost recovery processes, including but not limited to the [DPP] and Transmission Planning Process.”

3.2.4 Summary of Issues or Concerns Raised

- In the April 2024 scoping ruling, the CPUC expressed concern about affordability and energization. They highlighted that electricity rates increased at a rate that exceeded inflation and were projected to continue rising. They were concerned that additional ratepayer spending on behind-the-meter and front-of-the-meter could exacerbate affordability issues. This prompted a need to reassess the TE Rebate Program. In terms of energization, the CPUC said energization delays are a “significant barrier” to the state’s transportation electrification goals, and without adequate utility-side infrastructure, charging ports cannot be energized.³⁶
- In October 2025, the CPUC requested party comments on the staff-developed modeling inputs and assumptions and CDM. A webinar was held to familiarize stakeholders with the TEPP I&As and CDM.³⁷
- Following the October 2025 request for comments, many parties submitted comments and reply comments to the docket expressing concern that the methodologies presented require revision and that the Commission has not explained how these methodologies and

³³ Ibid.

³⁴ Ibid.

³⁵ CPUC. “Transportation Electrification Proactive Planning: Modeling Inputs & Assumptions Report. Draft for Public Comment.” August 25, 2025. <https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/transportation-electrification/tepp-modeling-inputs-and-assumptions-report.pdf>.

³⁶ CPUC. “Assigned Commissioner’s Scoping Memo and Ruling.” April 12, 2024. <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M529/K525/529525879.PDF>.

³⁷ CPUC. “Transportation Electrification Proactive Planning.” Accessed June 15, 2026. <https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/infrastructure/transportation-electrification/transportation-electrification-proactive-planning>.

processes would coordinate with other related analyses, such as the pending loads and scenario analysis being conducted in the DPP. Other items covered in party comments include:

- Technical input and data were provided by parties, with suggestions on how to modify the proposed methodologies.
- Multiple commenters state that the TEPP model(s), particularly the CDM, overlap with other efforts related to distribution forecasting, planning, and investment, including scenario planning and pending loads the Commission required the utilities to implement, the Electrification Impacts Study Part 2, and the utilities' investment proposals within their individual rate cases.
- Several commenters pointed out that Guidehouse's work on the TEPP methods took place over the course of 2025 without any stakeholder input. SCE recommends that staff develop a plan to augment and refine the I&A and CDM based on the feedback from stakeholders, and then present the workplan in a workshop for feedback and comment.
- As of July 2026, no further rulings or decisions have been issued, and the rulemaking has been reassigned from President Alice Reynolds to President John Reynolds.

3.3 Southern California Edison 2025 General Rate Case Supplemental Load Growth Forecast Methodology ([A2305010](#))

3.3.1 Background

- SCE notes that California decarbonization policies, particularly in electrifying the transportation sector, are increasing the pace and uncertainty of electric load growth.³⁸
- Load growth projections typically start with the CEC's forecast. The 2020 forecast was the most current at the time the 2025 GRC forecast was prepared, which, SCE states, does not incorporate approved or future policies. Therefore, SCE states that it was necessary to develop a supplemental TE load growth forecast.
- Another factor is the long lead times required to obtain transformers and other equipment to upgrade distribution or transmission facilities needed to integrate large loads.
- Following the load forecasting process, SCE identifies "solutions" and categorizes them into plans, including a Transportation Electrification Grid Readiness (TEGR) plan within the 2025 GRC filing.
- In August 2025, SCE presented an oral argument to the CPUC for authority to increase its authorized revenues for electric service in 2025.³⁹
- On September 18, 2025, the CPUC issued its decision on SCE's 2025 GRC.⁴⁰

³⁸ CPUC. "Application Of Southern California Edison Company (U 338-E) For Authority To Increase Its Authorized Revenues For Electric Service In 2025, Among Other Things, And To Reflect That Increase In Rates." May 12, 2023. <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M508/K571/508571681.PDF>.

³⁹ CPUC. "Application Of Southern California Edison Company (U 338-E) For Authority To Increase Its Authorized Revenues For Electric Service In 2025, Among Other Things, And To Reflect That Increase In Rates." August 15, 2025. <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M576/K882/576882051.PDF>.

⁴⁰ CPUC. "D2509030 Decision on Test Year 2025 General Rate Case for Southern California Edison Company." September 23, 2025. <https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=580788967>.

3.3.2 Proactive Definitions, Frameworks, or Rationales

SCE's rationale for developing a load forecast supplemental to the CEC's, and identifying needs and solutions from that forecast, is twofold. First, the CEC forecast was outdated when the SCE was developing the rate case and did not include all of the relevant approved policies. Second, SCE noted long lead times needed to procure necessary infrastructure.

3.3.3 New or Modified Methodologies

- The TEGR load growth projections consider state policies and SCE's own knowledge of interconnection requests from electrifying fleets to create a supplemental load growth forecast to the CEC's forecast.
- The supplemented forecast incorporates TE load profile assumptions that resemble a time-of-use rate-responsive load profile.
- The TEGR plan lays out SCE's proposed grid readiness actions to accommodate California's policies around TE. It uses a 10-year planning horizon and identifies projects with operational dates outside of the GRC window. The TEGR plan identified a significant increase in the volume of substation A-bank projects, which have long lead times for deployment.
- The TEGR analyses resulted in approximately 10–15% of SCE's sub-transmission and distribution systems being included for proposed grid development.
- In the CPUC decision, the TEGR model was authorized and adopted, but the CPUC reduced SCE's revenue request for the TEGR by 50% "because of uncertain market conditions."⁴¹

3.3.4 Summary of Issues or Concerns Raised

- The TEGR plan is based on SCE's analysis of load growth projections. At least one intervenor (Public Advocates Office) takes issue with the projections and provides a different analysis of policies, charging behaviors, and load shapes.
- Concern about rate increases is raised by multiple intervenors.
- Some intervenors are concerned that SCE's TEGR plan is not ambitious enough in terms of proactive investments to support TE.
- In the August 2025 hearing, a representative from the Small Business Utility Advocates said that "it is important that if Edison seeks further approval, a part of reasonableness review shows that it consider non-wires interventions that would avoid the need for those capital expenditures such as super off-peak time-of-use, efficiency upgrades, increase in storage, or DER options. That would avoid those capital expenditures."⁴²
- In the August 2025 hearing, a representative from the Natural Resources Defense Council (NRDC) identified several risks with proactive investments: "There are significant economies of scale associated with [grid] upgrades. Upgrades are more efficient when done together rather than piecemeal. An infrastructure built early now will still be used. There are

⁴¹ Ibid.

⁴² CPUC. "Application Of Southern California Edison Company (U 338-E) For Authority To Increase Its Authorized Revenues For Electric Service In 2025, Among Other Things, And To Reflect That Increase In Rates." August 15, 2025.
<https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M576/K882/576882051.PDF>.

significant costs associated with short-term underinvestment that delay compliance for state, local, regional, federal laws and regulations” and they urge the “Commission to adopt the proposed electrification balancing account [because it...] is a prudent solution which addresses load growth uncertainty and risks to ratepayers.” This approach, from their view, helps to “address unforeseen upgrades and [ensure] that any unspent funds are returned to ratepayers.” In this argument, a spokesperson from the NRDC commented that the CPUC “proposal strikes the correct balance between proactive transportation electrification investments protecting ratepayers” and that the “grid investments will put a downward pressure on rates for all Californians.”⁴³ The Commission did not adopt the proposed two-way balancing account for transportation electrification investments. Instead, D.25-09-030 authorized a memorandum account to track incremental TE-related grid-readiness expenditures, with recovery subject to a reasonableness review.

⁴³ Ibid.

4.0 Colorado

The two Colorado proceedings that deal with proactive planning and investments that are described in this document are listed below.

- Colorado PUC Proceeding to Study Potential Barriers to Beneficial Electrification (BE) and DERs (Proceeding No. 23M-0464EG).
- Public Service Company of Colorado 2024 Distribution System Plan (Proceedings 24A 0547E and 25A-0061E).

4.1 Colorado Public Utilities Commission Proceeding to Study Potential Barriers to Beneficial Electrification and Distributed Energy Resources ([Proceeding No. 23M-0464EG](#))

4.1.1 Background

- The Colorado Public Utilities Commission (PUC) opened proceeding No. 23M-0464EG in September 2023. The goals included:
 - Completing a legislatively required study of potential barriers to BE and DERs
 - Examining existing utility tariffs and interconnection policies and practices to determine if they pose barriers
 - Examining whether distribution system planning (DSP) can better plan for future BE and DER investments to align with the state's goals
 - Considering the application of cost allocation in grid upgrades
- The Hearing Commissioner (Megan Gilman) initially issued two sets of questions to the IOUs. In the fall of 2023, the Commission began to hear concerns about Xcel Colorado's delays to connect new electric capacity in certain areas. Commissioner Gilman's questions focus on understanding the full suite of processes, policies, timelines, and customer touchpoints involved in connecting new buildings, upgrading existing buildings, and integrating BE and DERs. Her inquiries explore how utilities manage new all-electric and mixed-fuel construction, service upgrades, infrastructure reinforcement needs, cost-allocation practices, rate selection, and capacity forecasting. She also probes utility support for customers, especially affordable housing developers, in navigating electrification, EV-charging requirements, interconnection procedures, and building code compliance. Overall, the questions aim to identify procedural barriers, transparency gaps, and opportunities to better align utility practices with Colorado's electrification and policy goals.
- On March 14, 2024, a consultant study, Impact of Investor Owned Utilities' Tariffs, Policies, and Practices on Beneficial Electrification and Distributed Energy Resources, was posted to the Commission website.⁴⁴

⁴⁴ Colorado PUC. "Impact of Investor Owned Utilities' Tariffs, Policies, and Practices of Beneficial Electrification and Distributed Energy Resources." March 2024.
<https://drive.google.com/file/d/1dxKr9zLf9mmljLOnOhq4mcSYYK89PqW/view>.

4.1.2 New or Modified Methodologies

- After a series of workshops, on April 18, 2024, the Hearing Commissioner issued an interim decision recommending improvements to Xcel Colorado’s processes to reduce barriers.⁴⁵ Short-term recommendations include:
 - Improve communications around receiving and processing information for new or upgraded service, including enhancing the current “conceptual capacity check” process
 - Improve transparency around cost allocation and alternatives available when the company determines that new load will require grid upgrades
 - Load forecasting criteria should include compliance with state goals, including BE, and the company should consult with municipalities and large developers on their energy plans to better inform load forecasting
- Long-term recommendations include:
 - Consider new capacity availability maps on the company’s website
 - Consider a capacity reservation pilot to be included in the 2024 DSP filing
 - Consider a “cluster study” approach to projects that are all on a similar timeframe
 - Consider preparing 2024 DSP forecasts using information from municipalities’ current energy plans

4.1.3 Summary of Issues or Concerns Raised

The issues described here are summarized from the Colorado Commission’s Interim Decision filed in April 2024.⁴⁶

- Stakeholder input included concerns that the current practices and policies related to serving new or expanded load have created an inefficient system which results in reactive, piecemeal additions to the system. This obfuscates, delays, or disincentivizes customer adoption of electrification and may hinder other developments such as housing.
- Xcel stated that the biggest challenges in ensuring timely upgrades to the distribution system are supply chain issues and permitting. The Hearing Commissioner responded to this with several recommendations on how the company could respond to these challenges.
- Issues around cost allocation for grid upgrades were raised, but the Hearing Commissioner notes that revisiting line extension policy and cost allocation principles is not appropriate for this proceeding.
- The Hearing Commissioner recommends “immediate steps” be taken to improve the communication and processes for service requests, distribution system upgrades, and forecasting.

⁴⁵ Colorado PUC. “Decision No. R24-0242-I.” April 18, 2024.

https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=1019380.

⁴⁶ Ibid.

4.2 Public Service Company of Colorado 2024 Distribution System Plan ([Proceeding 24A-0547E](#) & [25A-0061E](#))

4.2.1 Background

- In May 2024, the Colorado Legislature passed SB 24-218, An Act to Modernize Energy Distribution Systems. SB 24-218 impacts how the Commission and utilities address DSP going forward. Specific to utility DSPs, the legislation requires a DSP to create “sufficient hosting capacity across its electrical distribution system to affordably and reliably” support the implementation of state and national targets and regulations regarding air quality, transportation, and building electrification, housing, and energy resource mix.
- SB 24-218 requires the PUC to develop a cost recovery mechanism to allow utilities to recover costs for distribution activities and corresponding budgets that strategically benefit or advance the targets, standards, plans, and regulations named in the statute and summarized above. If the Commission finds that the distribution activities and corresponding budgets “affordably and strategically benefit or advance” the goals of the legislation, cost recovery **must occur** through the Grid Modernization Adjustment Clause (GMAC).⁴⁷ For costs that the commission finds do not benefit or advance the goals of the legislation, recovery **may** occur through the GMAC if the utility meets criteria established in the performance-based framework approved by the commission pursuant to an earlier section of the law. As of the writing of this report, that performance-based framework has not yet been developed.
- SB 24-218 requires utilities to present at least two future scenarios with corresponding investments.
- Public Service Company of Colorado submitted its 2024 Distribution System Plan on December 16, 2024.⁴⁸
- The company employed two load forecasting modeling exercises: 1) the LoadSEER model, and 2) a longer-term “Grid of the Future” planning exercise conducted by Kevala.⁴⁹
- The PUC issued its decision on the DSP on December 15, 2025.⁵⁰

4.2.2 Proactive Definitions, Frameworks, or Rationales

- Xcel states that the DSP increases the “speed and scale of grid investments through proactive planning.” The company discusses proactive planning as being able to create a distribution system that can facilitate customer choices in light of state policies and advance overarching policy goals. They state that incremental planning approaches are insufficient to meet the new expectations of the energy system.

4.2.3 New or Modified Methodologies

- In the DSP, the company describes its proactive planning approach as a physical build-out of the distribution system that is aligned with the company’s integrated distribution planning

⁴⁷ Colorado Legislature. “Senate Bill 24-218.” Accessed June 13, 2026.
https://leg.colorado.gov/bill_files/45588/download.

⁴⁸ Xcel Energy. “Distribution System Plan.” December 16, 2024.
https://www.dora.state.co.us/pls/efi/efi.show_document?p_dms_document_id=1032849&p_session_id=

⁴⁹ Ibid.

⁵⁰ Colorado PUC. “Decision No. C25-0903.” December 15, 2025.
https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=1054222.

standards. This means feeder utilization is capped at 75% of continuous rating, to allow the system to absorb growth as it is being built out and ensure flexibility. They say that this proactive approach will reduce rework and disruption that a more incremental approach could entail.

- For distribution system capacity planning, the utility is required by SB 24-218 to present at least two future scenarios with corresponding investments to show different future states of the distribution system, and this must include one scenario that incorporates load and managed generation flexibility. The load forecasting process begins with determining base load by using data collected through supervisory control and data acquisition, which is then fed into LoadSEER to produce time-series data that then is weather-normalized. The tool then applies spatial allocation to model technology adoption and usage as a premises level.
- In determining which portions of the system to propose system upgrades, the new statute requires them to prioritize capacity investments in areas that are at or near the hosting capacity limits or that are projected to have energization loads that cannot be met without an upgrade. Also, the statute requires them to prioritize upgrades targeted at improving infrastructure for income-qualified or disproportionately impacted communities with residential capacity constraints.
- The company then conducts a Grid Needs Assessment, a summary of projected overloads and contingency risks over the 10-year forecast for distribution feeders and substation banks. The 2024 DSP identified 901 distribution risks, up from 270 in the previous DSP. This increase is due to 1) TE and BE and 2) adoption of a planning load limit standard that caps feeder utilization to 75% of continuous rating. They do this because the goal of this DSP is to “proactively plan investments to align with evolving customer needs and state electrification and emission reduction goals.” This allows them to stay ahead of rapidly growing load.
- Xcel is required to publish monthly hosting capacity updates by the end of 2026. They are also required to publish 576- and 8,760-hour results for the hosting capacity analysis by the end of 2027.
- Pursuant to SB 24-218, Xcel proposed the creation of a GMAC. With respect to new, proposed spending presented in the DSP, the company has two categories of costs that it proposes to recover through the GMAC. “Type 1” investments are the company’s categorization of activities that strategically benefit or advance legislative/state/local goals. The Commission must determine whether a projected activity “strategically and affordably” furthers a legislative priority. According to state law, if such a determination is made, recovery must occur through the GMAC. Xcel says, with respect to affordability, “the company’s proactive planning process results in affordable solutions to meet the identified need by efficiently deploying capital and iterating on an annual basis to ensure capital is only deployed if and when needed.” “Type 2” investments are the activities undertaken as part of the DSP that do not qualify as Type 1 investments, such as extensions for new service that do not serve policy goals. Type 2 costs would be subject to a performance-based framework.
- With regard to Type 1 investments, the Commission approved the company to recover labor and operations and maintenance costs through the GMAC. They state that personnel are an essential part of achieving state policy goals. Capacity expansion activities are approved for GMAC recovery because the investments will further the broad purposes of SB 24-218. “Asset health and reliability” activities are not approved for GMAC recovery because the company has not met its burden to support that its proposed investments would “increase reliability” as required by the statute.

- With regard to Type 2 investments, the Commission decided that more process is required to develop a performance-based framework before it can allow any recovery of those kinds of activities through the GMAC. They expect the process to develop a framework to ensure that GMAC recovery is linked to interconnection time, system reliability, customer service, hosting capacity analysis data availability and usability, availability of a flexible interconnection tariff, dynamically integrating demand and supply, and distribution asset utilization (or other metric to incentivize an optimized peak load impact of EV and BE).

4.2.4 Summary of Issues or Concerns Raised

- The staff were concerned that, in its prioritization of distribution system investments, the company's approach of triggering an upgrade for any feeder forecasted to surpass the 75% use threshold needs "proper safeguards." The staff also were concerned that the company does not consider the inherent uncertainty in probabilistic forecasting. The company is concerned about the risk of underbuilding, and the staff is concerned about the risk of overbuilding.
- The Southwest Energy Efficiency Project (SWEEP)/NRDC is similarly concerned that the company's approach does not adequately account for the variation in time it takes for feeders to move from 75% to 100% of capacity. They recommended a time-based planning approach wherein the company would calculate the year a feeder or substation bank is projected to reach 100% capacity and then designate the N-0 overload trigger year by moving the date back based on the necessary project lead time (e.g., 2 years for feeders, 3 years for banks/transformers). This approach would mean the company would consider differences in timeframes required for different distribution system infrastructure to reach an overloaded state (N-0). Results from analysis performed by SWEEP/NRDC suggested that if time-based planning is put into practice for the next DSP, there would be fewer feeder upgrades but more bank upgrades than the strict 75% planning load limit method. The Commission found that this approach would provide an informative counterpoint to the company methodology in the next DSP, directing the company to include it.
- The company clarified that the 75% peak load standard is a trigger for a project, but whether it gets funded depends on the overall risk profile for the project relative to the rest of the system. The company considers the load growth rate and allows some feeders to be loaded up to 100%. The company opposes the time-based approach proposed by SWEEP/NRDC.
- The investments proposed in the DSP are overwhelmingly due to the ageing and already-constrained system. Multiple entities emphasize that electrification is not the primary cause of the capacity investments. 173 of the 180 capacity projects identified in the Grid Needs Assessments are aimed at solving short-term needs.
- One of the short-term recommendations from Decision No. R24-0242-I (Proceeding No. 23M-0464EG) was to "improve communications around receiving and processing information for new or upgraded service, including enhancing the current "conceptual capacity check" process." It appears that the company did not adequately address this issue in the 2024 DSP, with the commission finding that capacity checks provide "only modest clarity regarding future system capacity requirements" and directing the company to conduct a more fulsome analysis of all forecasts so that the claims regarding needed investment are fully supported. Specifically, the company is required to present the historical number and MW requested for capacity checks, and the number and MW values of capacity check requests actually served.

5.0 Massachusetts

This section describes two related processes in Massachusetts deriving from legislative action and building up more than a decade of grid modernization and distributed generation planning activities:

- Massachusetts Electric Sector Modernization Plans (ESMPs) of the Electric Distribution Companies (EDCs). (Dockets No. DPU 24-10, 24-11, and 24-12).
- Investigation into the Long-Term System Planning Process (LTSP). (Docket 25-20).⁵¹

Figure 2 shows a timeline of proactive-related developments in Massachusetts.

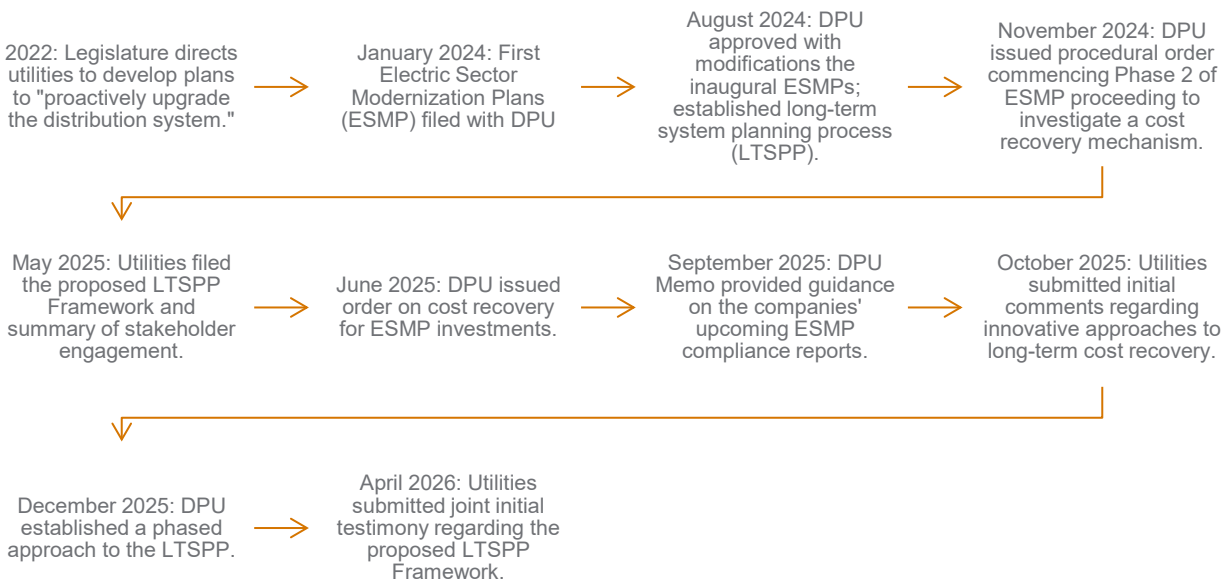


Figure 2. Timeline of Proactive-Related Developments in Massachusetts (2022–2026)

⁵¹ Massachusetts pursued and implemented grid modernization and distributed generation interconnection activities through regulatory action in the decade or so preceding the 2022 legislative action. Grid modernization efforts commenced with proceedings in 2012, followed by grid modernization plan filings in 2015 and 2018 (see details <https://www.mass.gov/grid-modernization-and-advanced-metering-infrastructure>). Additionally, LTSP has been informed by the Provisional Program, which was, in 2024, a "new, provisional framework for planning and funding these [electric power system] upgrades to the EPS [electric power system] to foster timely and cost-effective development and interconnection of DG ("Provisional Program")." Massachusetts DPU. "DPU 22-52, 22-53, 22-54, 22-55." June 4, 2024. <https://d3i1pf1zzeh4ol.cloudfront.net/4f80132a-7f05-4174-9757-9d91ddaa311b.pdf>. For more details on the interplay between CIP, ESMP, and LTSP, see <https://d3i1pf1zzeh4ol.cloudfront.net/8126ca4b-80e8-4828-b14e-b447df342b2c.pdf>.

5.1 Massachusetts Electric Sector Modernization Plans of the Electric Distribution Companies (Dockets No. [DPU 24-10](#), [24-11](#), and [24-12](#))

5.1.1 Background

- The 2022 “Act Driving Clean Energy and Offshore Wind,” codified as G.L. c. 164, § 92B, directed utilities to develop an ESMP and “to proactively upgrade the distribution and, where applicable, transmission systems” and provides the elements of a standard of review for the Department of Public Utilities (DPU) to use.⁵²
- The legislature directed the DPU to evaluate each ESMP and approve; approve with modifications; or reject each ESMP. Section 92B (d) further directs that for the DPU to approve an ESMP, the Department must find that the ESMP 1) provides net benefits to customers and 2) meets a set of required objectives (see the “Proactive Definitions, Frameworks, and Rationales” section for the list of these objectives).
- The utilities submitted their respective ESMPs on January 29, 2024 in separate but closely linked dockets. The DPU issued an Interlocutory Order on February 20, 2024 deferring the review of cost recovery mechanisms, budgets, capital investment projects, cost allocation, rate design, and performance metrics to subsequent phases or proceedings.⁵³
- In August 2024, the DPU approved with modification the inaugural ESMPs filed by utilities and established September 30 and March 31 as biannual reporting filing dates.⁵⁴
- Also, in the August 2024 ESMP Order, the Department directed the establishment of a 6-month LTSP stakeholder working group to discuss a proposed LTSP framework. See Section 5.2 for a discussion of the LTSP.
- In November 2024, the DPU commenced Phase 2 of the ESMP proceeding to investigate an interim annually reconciling cost recovery mechanism for ESMP investments, and to establish near-term metrics and reporting requirements.⁵⁵ This procedural order also requested comments from parties regarding innovative approaches to cost recovery that can further state priorities. Comments were requested on “information and data on innovative approaches to cost recovery, in particular, to facilitate accelerated electrification and/or grid modernization efforts” and “discussion on performance metrics and incentives applicable to longer-term cost recovery considerations.”

⁵² Massachusetts Legislature. “Section 92B.” Accessed June 13, 2026.

<https://malegislature.gov/Laws/GeneralLaws/PartI/TitleXXII/Chapter164/Section92B#:~:text=The%20electric%20company%20shall%20be,heard%20in%20a%20public%20hearing>.

⁵³ Massachusetts DPU. “DPU 24-10, 24-11, 24-12.” February 20, 2024.

<https://fileservice.eea.comacloud.net/V3.1.0/FileService.Api/file//icbjhgci?zQIBX+9F0KczRH9bUPVtXmFJ0ioKRMXdZYr4j7j/42qk9v9pxUxyG6LkaCeWBSjqbmMINqhcSkxPf0qUr1gASPKrYE1qejevbf677PtCVStUdHoHpEGELGLGjR+ZpYgt>.

⁵⁴ Massachusetts DPU. “DPU 24-10, 24-11, 24-12.” August 29, 2024.

<https://fileservice.eea.comacloud.net/V3.1.0/FileService.Api/file//iggdiddj?dFRGoJKkAru50g4f2swgdmFJ0ioKRMXdZYr4j7j/42qk9v9pxUxyG6LkaCeWBSjqbmMINqhcSkxPf0qUr1gASPKrYE1qejevbf677PtCVStUdHoHpEGELGLGjR+ZpYgt>.

⁵⁵ Massachusetts DPU. “Phase II Procedural Notice.” November 21, 2024.

<https://fileservice.eea.comacloud.net/V3.1.0/FileService.Api/file//iicfciie?fCe7NJzUC9EKH6P2Av/M9MEmiDhMBXK0ednWT8WFP5Ok9v9pxUxyG6LkaCeWBSjqbmMINqhcSkxPf0qUr1gASPKrYE1qejevbf677PtCVStUdHoHpEGELGLGjR+ZpYgt>.

- On June 13, 2025, the DPU issued an order setting parameters for grid investments resulting from the first iteration of ESMPs. The DPU approved an interim, annually reconciling cost recovery mechanism and identified the types of projects that will be approved for cost recovery through the ESMP mechanism.⁵⁶ In the same order (June 2025), the DPU approves some, but not all of the proposed ESMP investments proposed by utilities Eversource, National Grid, and Unitil. DPU approved a combined set of utility projects totaling \$863 million out of a proposed \$2,540 million.
- On September 9, 2025, a Hearing Officer Memorandum provided guidance on the form and content of the companies' September 2025 and March 2026 ESMP compliance reports, including reporting on performance metrics and investments for ESMPs.⁵⁷

5.1.2 Proactive Definitions, Frameworks, or Rationales

- Massachusetts law (G.L. c. 164, § 92B) directs each electric company to develop an ESMP to proactively upgrade its distribution and, where applicable, transmission systems to achieve the following objectives: 1) improve grid reliability, communications, and resiliency; 2) enable increased, timely adoption of renewable energy and distributed energy resources; 3) promote energy storage and electrification technologies necessary to decarbonize the environment and economy; 4) prepare for future impacts on the transmission and distribution systems; 5) accommodate increased transportation electrification, increased building electrification, and other potential future demands on distribution and, where applicable, transmission systems; and 6) minimize or mitigate impacts on ratepayers, thereby helping the Commonwealth realize its statewide policy mandates.
- The DPU identified the ESMPs as strategic roadmaps for accelerated electric company investments geared toward modernizing and upgrading the electric grid, above and beyond "core" company investments for ensuring the safety, security, and reliability of the electric grid.

5.1.3 New or Modified Methodologies

- In the inaugural ESMPs, the utilities stated that the investments proposed in the ESMPs were not intended to meet a near-term customer or reliability need; rather, they were "incremental" and intended to meet one or more statutory objectives.
- The utilities were required by law to prepare electric demand forecasts for three different planning horizons, including 5-year and 10-year forecasts and a demand assessment through 2050 to account for future trends. The utilities' 5-year and 10-year forecasts to inform the ESMPs were the same forecasts utilized by the utilities for their business-as-usual, "core" capital planning, which they update annually.⁵⁸ The utilities' demand

⁵⁶ Massachusetts DPU. "DPU 24-10-A, 24-11-A, 24-12-A." June 13, 2025.

<https://fileservice.eea.comacloud.net/V3.1.0/FileService.Api/file//aedeibhij?gW0WCcv4f6NebTNAPadCfW eQrh7dXR/Utfj5zj+lw7CPcSxI+blU344Khxm+qpOeg0hKFj9M9l/xQR8+/8GqPvdGgrFe6XR6nglfa80wd3rx FD8G4j981M2Rna9aVTXA>.

⁵⁷ Massachusetts DPU. "Memorandum on Metrics and Reporting Requirements." September 9, 2025.

<https://fileservice.eea.comacloud.net/V3.1.0/FileService.Api/file//aeffdhgj?PbB7KkMGkGEQksKyzejsX2s LVPSi7NdqNUTTiLCXtaiPcSxI+blU344Khxm+qpOeg0hKFj9M9l/xQR8+/8GqPvdGgrFe6XR6nglfa80wd3rx FD8G4j981M2Rna9aVTXA>.

⁵⁸ Massachusetts DPU. "DPU 24-10, 24-11, 24-12." August 29, 2024.

<https://fileservice.eea.comacloud.net/V3.1.0/FileService.Api/file//igggdddj?dFRGoJKkAru50g4f2swgdmFJ 0ioKRMXdZYr4j7j/42qk9v9pxUxyG6LkaCeWBSjqbmMINqhcSkxPf0qUr1gASPKrYE1qeivebf677PtCVStU dHoHpEGELGLGjR+ZpYgt>.

assessments were largely informed by the Commonwealth's Clean Energy and Climate Plans and 2050 Decarbonization Roadmap.⁵⁹

- The Attorney General's office suggested that the DPU develop an export tariff methodology for cost allocation and cost recovery to enable utilities to proactively plan for DER interconnection over the long term.⁶⁰
- To provide sufficient revenue to fund the required upgrades, the EDCs proposed that a reconciling mechanism be developed to recover the costs of ESMP investments.
- The utilities stated that they were not seeking preauthorization or preapproval of their budgets but rather that the DPU should establish a budget cap for the proposed cost recovery mechanisms. They argued that prudence review at the time of cost recovery would be a check on utility spending.⁶¹
- The June 2025 DPU ruling on cost recovery for ESPM investments created a new mechanism, called the Electric Sector Modernization Plan Factor, that will be interim and annually reconciled. In the long term, cost recovery will be accomplished through base rates.⁶² Costs eligible for recovery include: 1) establishing projects to install and manage technology hardware such as early fault detection and expanded conservation voltage reduction; 2) initiating programs and demonstration projects to advance virtual power plants, use of distributed energy resources for grid services, and investments in new energy customer portals and enabling technologies; 3) making platform investments in the utilities' distribution systems geared towards leveraging data, digitalization, and other platforms to optimize infrastructure and meet evolving customer needs; 4) making targeted resiliency investments involving undergrounding, reconductoring, and other storm hardening infrastructure upgrades; 5) implementing and coordinating integrated energy planning with Massachusetts gas utilities; 6) implementing a Community Engagement Stakeholder Advisory Group; 7) establishing three National Grid electric vehicle highway charging substation projects; and 8) covering related administrative costs. Several projects are continuations of the companies' and DPU's grid modernization efforts implemented prior to the 2022 legislative action. In other words, the ESMP mechanism does not appear to be approved for use in recovering costs such as substation and distribution feeder projects. The DPU stated that they were trying to maintain a balance between progress on grid modernization and the achievement of Massachusetts' policy goals, while ensuring affordability for ratepayers.
- In Phase II ESMP filings, each utility submitted a jointly developed model tariff and a company-specific exemplar tariff with proposed terms and conditions of the cost recovery mechanism. Each company proposed to allocate its annual revenue requirement for cost recovery through the Electric Sector Modernization Plan Factor to each rate class using a distribution revenue allocator, or DRA that was established in each utility's most recent base distribution rate proceeding. The DRA allocates cost based on relative sales to each rate class. The DPU wants to monitor this and eventually may change cost allocation to better

⁵⁹ Massachusetts DPU. "Mitigating Greenhouse Gas Emissions." Accessed August 10, 2026. <https://www.mass.gov/mitigating-greenhouse-gas-emissions>.

⁶⁰ Massachusetts DPU. "DPU 24-10, 24-11, 24-12." August 29, 2024. <https://electricgrid.mass.gov/wp-content/uploads/2025/07/D.P.U.-24-10-11-12-ESMP-Final-Order-8.29.24.pdf>.

⁶¹ Ibid.

⁶² Massachusetts DPU. "DPU 24-10-A, 24-11-A, 24-12-A." June 13, 2025. <https://fileservice.eea.comacloud.net/V3.1.0/FileService.Api/file//aedeibdcj?ScNUM2JbDRlyMtx/w6Ugp62sCSWgooFb4RbJ6xIh+PcSxI+blU344Khxm+qpOeg0hKFj9M9l/xQR8+/8GqPvdGgrFe6XR6nglfa80wd3rxFD8G4j981M2Rna9aVTXA>.

align with cost causation, including differentiating costs based on capital or operating and maintenance expenditures.⁶³

- The Commission will conduct prudency reviews on each annual ESMP filing, rather than simply an end-of-term review.⁶⁴
- To allow stakeholders to have a better understanding of progress on electrification goals and uncertainty regarding how quickly and in what locations electrification load will materialize, utilities are expected to report annually updated information about electrification loads (ESMP and non-ESMP) connecting to the grid. This will help provide context for load forecasts and proposed future grid investments. Utilities are requested to distinguish between the new loads with EV, non-EV electrification, and other large loads (e.g., new housing development, data centers, advanced manufacturing). Utilities must also provide in their reports a comparison of their forecasted versus actual demand.⁶⁵
- In the March 2026 ESMP Biannual Report Template provided in October 2025, utilities are expected to provide data relating to their most recently recorded annual peak, baseload, solar, EV, heating, storage, demand response, energy efficiency, and variance of actuals versus forecasts.⁶⁶ In July 2026, the DPU released a memorandum that updated the ESMP Biannual Report Template to include the Grid Services Compensation Framework and a corresponding spreadsheet “Summary of Grid Services Compensation Fund Projects.”^{67,68}

5.1.4 Summary of Issues or Concerns Raised

- On October 1, 2025, EDCs separately submitted initial comments regarding innovative approaches to longer-term cost recovery in response to the DPU’s request for comments in the November 2024 procedural order. In October 2025, Massachusetts utilities proposed alternative cost recovery mechanisms in response to the Commission’s June order. Eversource and Unitil recommended that the Commission build on existing PBR frameworks, while National Grid recommended that the Commission build on an existing

⁶³ Ibid.

⁶⁴ Ibid.

⁶⁵ Massachusetts DPU. “Memorandum on Metrics and Reporting Requirements.” September 9, 2025. <https://fileservice.eea.comacloud.net/V3.1.0/FileService.Api/file//aeffdhgj?PbB7KkMGkGEQsKyzejsX2sLVPSI7NdqNUTTiLCXtaiPcSxI+blU344Khxm+qpOeg0hKFj9M9l/xQR8+/8GqPvdGgrFe6XR6nglfa80wd3rxFD8G4j981M2Rna9aVTXA>.

⁶⁶ Massachusetts DPU. “DPU 24-10/11/12 March ESMP Biannual Report Template.” October 30, 2025. <https://fileservice.eea.comacloud.net/V3.1.0/FileService.Api/file//aeghacehe?Dn72VFSFXjq3gd3ifOxhGmZw4DJkmGuEPwz9YhdTp02PcSxI+blU344Khxm+qpOeg0hKFj9M9l/xQR8+/8GqPvdGgrFe6XR6nglfa80wd3rxFD8G4j981M2Rna9aVTXA>.

⁶⁷ Massachusetts DPU. “Electric Sector Modernization Plan September Reports.” July 21, 2026. <https://d3i1pf1zzeh4ol.cloudfront.net/3b91cbe7-067c-4d87-a177-5d90cd809d3c.pdf>.

⁶⁸ The Massachusetts DPU and Massachusetts Clean Energy Center (MassCEC) jointly developed the Grid Services Compensation Framework, which is an “initial compensation framework for DERs providing location-specific grid services to the distribution grid.” MassCEC. “Grid Services Study.” Accessed August 10, 2026. <https://www.masscec.com/resources/grid-services-study>.

tracker and reconciling mechanism.^{69,70,71} Multiple parties submitted comments, and the utilities jointly submitted reply comments on November 26, 2025.⁷² The points below are summarized from comments filed to the docket on longer-term cost recovery considerations.

- There was general agreement that new planning solutions are needed to transition the power system to fully support the achievement of the State's policy goals. To accomplish the transformations needed, the utilities argued that they should be allowed to implement the ESMPs in a flexible way that adapts to evolving circumstances. Other parties described a "collaborative, iterative process" that should be implemented over the ESMP 5-year term.
- Regarding load forecasting, concerns were raised that the utilities should collaborate and align load forecasting methodologies, including sensitivities for key assumptions. Some parties want the utilities to comprehensively consider load management potential for buildings, vehicles, storage, and demand response.

5.2 Investigation into the Long-Term System Planning Process ([Docket DPU 25-20](#))

5.2.1 Background

- In DPU 20-75, the DPU investigated both near-term and long-term alternatives to the Cost Causation Principle as it applies to the interconnection of DG. Through this investigation, the DPU established the "Provisional System Planning Program," also sometimes called the Capital Investment Project (CIP) process, which applied to solar and energy storage projects. The Provisional Program allows the EDCs to file certain infrastructure upgrade proposals. Eversource and National Grid each developed Provisional System Planning Program CIPs. Massachusetts legislation then created the requirement for EDCs to file ESMPs to proactively upgrade the distribution system, and the DPU directed in its ESMP Order that the LTSP would replace the Provisional System Planning Program and CIP proposal process. The EDCs were directed to establish a six-month stakeholder working group and file a final report for DPU review.

⁶⁹ Massachusetts DPU. "Initial Comments Regarding Long-Term Cost Recovery of Electric Sector Modernization Plan Investments." October 1, 2025.

<https://fileservice.eea.comacloud.net/V3.1.0/FileService.Api/file//aegbjbbbe?AnbWHlC9HCpCiRCZJq5MZJCYDN/DiDbHsUFX+Vfig6PcSxI+blU344Khxm+qpOeg0hKFj9M9I/xQR8+/8GqPvdGgrFe6XR6nglfa80wd3rxFD8G4j981M2Rna9aVTXA>.

⁷⁰ Massachusetts DPU. "Fitchburg Gas and Electric Light Company d/b/a Unitil Initial Comments on Electric Sector Modernization Plan Approaches to Cost Recovery." Accessed June 13, 2026.

<https://fileservice.eea.comacloud.net/V3.1.0/FileService.Api/file//aegbaiiae?pAcAXouj3ZiffjAtH4BVMl0HnvCcz/sZ6N5VHqqZ7niPcSxI+blU344Khxm+qpOeg0hKFj9M9I/xQR8+/8GqPvdGgrFe6XR6nglfa80wd3rxFD8G4j981M2Rna9aVTXA>.

⁷¹ Massachusetts DPU. "Comments of NSTAR Electric Company d/b/a Eversource Energy." October 1, 2025.

<https://fileservice.eea.comacloud.net/V3.1.0/FileService.Api/file//aegbaiigj?pAcAXouj3ZiffjAtH4BVMmsLVPSI7NdqNUTTiLCXtaiPcSxI+blU344Khxm+qpOeg0hKFj9M9I/xQR8+/8GqPvdGgrFe6XR6nglfa80wd3rxFD8G4j981M2Rna9aVTXA>.

⁷² Massachusetts DPU. "Joint Reply Comments of NSTAR Electric Company d/b/a Eversource Energy, Massachusetts Electric Company and Nantucket Electric Company Each d/b/a National Grid, and Fitchburg Gas and Electric Light Company d/b/a Unitil." November 26, 2025.

<https://fileservice.eea.comacloud.net/V3.1.0/FileService.Api/file//aehcihhfe?aYMKt6M3A+ApTJ/GZ1s4q7397esR9cO9SRd3olvwD+PcSxI+blU344Khxm+qpOeg0hKFj9M9I/xQR8+/8GqPvdGgrFe6XR6nglfa80wd3rxFD8G4j981M2Rna9aVTXA>.

- The DPU directed the utilities to establish a long-term stakeholder planning process beginning in October 2024, considering how best to enable distributed generation hosting capacity in specific locations and the role of flexible interconnection in avoiding the need for system upgrades.
- On May 9, 2025, the Companies filed the proposed LTSP Framework⁷³ and a detailed summary of areas of stakeholder consensus and non-consensus.⁷⁴ The Framework identifies the LTSP as the proactive system-level process to safely and reliably facilitate the efficient and cost-effective interconnection of DERs in support of the Commonwealth's policy goals, while also considering the potential impact of long-term electrification load.
- The DPU docketed this matter as 25-20.⁷⁵ In December 2025, the DPU established a phased approach to investigate the LTSP.⁷⁶ In that order, the DPU stated that it intends to "establish a uniform LTSP for the Distribution Companies to proactively upgrade their respective electric power systems to enable increased, timely interconnection of new distributed generation (DG), which will support the Commonwealth's policies."
- On April 10, 2026, the EDCs submitted initial joint testimony regarding the LTSP Framework.⁷⁷

5.2.2 Proactive Definitions, Frameworks, or Rationales

- The EDCs state that the LTSP "is intended to identify incremental investments, above and beyond the core investments designed for safe and reliable load growth, to proactively

⁷³ Massachusetts DPU. "Framework for the Long Term System Planning Process for Distributed Generation." May 9, 2025.

<https://fileservice.eea.comacloud.net/V3.1.0/FileService.Api/file//aechfbcaj?H2WP7YvZfmq7ZJ9JSMx8IDVOCwNmqqF7a2iSbK4sRtaPcSxl+blU344Khxm+qpOeg0hKFj9M9l/xQR8+/8GqPvdGgrFe6XR6nglfa80wd3rxFD8G4j981M2Rna9aVTXA>.

⁷⁴ Massachusetts DPU. "DPU 25-20 – Long Term System Planning Proposal Stakeholder Report." May 9, 2025.

<https://fileservice.eea.comacloud.net/V3.1.0/FileService.Api/file//aechfbbij?Wir/HPM0YwDRa1uRi44ZcGeQrh7dXR/Utfj5zj+lw7CPcSxl+blU344Khxm+qpOeg0hKFj9M9l/xQR8+/8GqPvdGgrFe6XR6nglfa80wd3rxFD8G4j981M2Rna9aVTXA>.

⁷⁵ Massachusetts DPU. "Docket 25-20." May 9, 2025.

<https://eeaaonline.eea.state.ma.us/dpu/fileroom/#/dockets/docket/12552>.

⁷⁶ Massachusetts DPU. "Joint Petition of NSTAR Electric Company d/b/a Eversource Energy; Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid; and Fitchburg Gas and Electric Light Company d/b/a Unitil for approval by the Department of Public Utilities of their Long-Term System Planning Process Proposal filed pursuant to Electric Sector Modernization Plan." December 16, 2025.

<https://fileservice.eea.comacloud.net/V3.1.0/FileService.Api/file//aehhjaie?+lCo4oVXrrl8NOhnLE8oVmZw4DJkmGuEPwz9YhdTp02PcSxl+blU344Khxm+qpOeg0hKFj9M9l/xQR8+/8GqPvdGgrFe6XR6nglfa80wd3rxFD8G4j981M2Rna9aVTXA>.

⁷⁷ Massachusetts DPU. "Joint Petition of NSTAR Electric Company d/b/a Eversource Energy; Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid; and Fitchburg Gas and Electric Light Company d/b/a Unitil for approval by the Department of Public Utilities of their Long-Term System Planning Process Proposal filed pursuant to Electric Sector Modernization Plan." April 10, 2026.

<https://fileservice.eea.comacloud.net/V3.1.0/FileService.Api/file//afacbdjjj?SV28oya3515g5uTEgbXIKTYOTJIXb74KK+K98p2SnmvPcSxl+blU344Khxm+qpOeg0hKFj9M9l/xQR8+/8GqPvdGgrFe6XR6nglfa80wd3rxFD8G4j981M2Rna9aVTXA>.

enhance the electric power system to accommodate future DG [distributed generation] growth.”⁷⁸

- A key proactive planning mechanism embedded in the ESMP framework created by the Legislature is the Long-Term System Planning Program requirement for enabling DER deployment. The purpose of the LTSP is to “expedite the cost-effective deployment and interconnection of DG” and to “support the Commonwealth’s policies.”

5.2.3 New or Modified Methodologies

- The LTSP will be investigated in two phases. Phase 1 of the docket will address:
 - Goals and scope of the LTSP
 - Establishment of an LTSP Framework
 - Timeline for the first LTSP filing and analysis
 - LTSP filing requirements
 - Process for transitioning from the Provisional Program to the LTSP
- Phase 2 will commence at a later date, and will include:
 - Flexible interconnection as it relates to the LTSP (including appropriate incentives)
 - Process for updating the LTSP
 - LTSP coordination with subsequent ESMP cycles
 - Updates to the companies’ respective “Standards for Interconnection of Distributed Generation” Tariffs
- The EDC’s proposed cost allocation is built on current planning and operational capabilities and is grounded in three core principles:
 - Beneficiary Pays: Costs of proactively planned infrastructure are allocated across DG and end-use load customers based on benefits received. This includes allocating costs across DG customers interconnecting to the same infrastructure at different points in time.
 - Sound Development Signals: DG is incentivized to interconnect in locations with available hosting capacity. LTSP areas will provide a proactive construction of hosting capacity, with specific reserved capacity for solar and ESS, thereby providing regulatory certainty of capacity availability, costs and timelines. Costs will be lower for DG that can leverage existing infrastructure or co-optimize infrastructure also required to meet other system needs.
 - Cost efficiency: The cost allocation framework should encourage efficient use of LTSP-enabled hosting capacity.
- The companies proposed a Long-Term System Planning Tariff to recover costs associated with Proactive Hosting Capacity Investments (PHCIs) approved through the LTSP. The tariff includes a Proactive Hosting Capacity (PHC) Fee, assessed on DG systems capable of

⁷⁸ Massachusetts DPU. “Framework for the Long Term System Planning Process for Distributed Generation.” May 9, 2025.

<https://fileservice.eea.comacloud.net/V3.1.0/FileService.Api/file//aechfbcaj?H2WP7YvZfmq7ZJ9JSMx8IDVOCwNmGkF7a2iSbK4sRtaPcSxI+blU344Khxm+qpOeg0hKFj9M9I/xQR8+/8GqPvdGgrFe6XR6nglfa80wd3rxFD8G4j981M2Rna9aVTXA>.

exporting more than 25 kW. The PHC Fee reflects each DG customer's pro rata share of PHCI costs.⁷⁹

- The EDCs also proposed a Long-Term System Planning Factor, applied to all customers receiving service under the Retail Delivery Service tariffs. The proposed Long-Term System Planning Factor is a reconciling charge, which, if approved as filed, would be updated annually, and recovered over a 20-year period.⁸⁰

5.2.4 Summary of Issues or Concerns Raised

- This LTSP investigation proceeding (Docket 25-20) is active, and multiple issues are under discussion. A May 2026 memorandum from the DPU listed current areas of non-consensus in the LTSP docket. These include:⁸¹
 - How energy storage will be incorporated into the LTSP framework
 - How the PHC fee will be calculated and applied
 - Distinctions between interconnection processes for PHC areas and non- LTSP areas
 - Timelines for utilities to conduct their first LTSP analysis and file investments proposals with the Department

⁷⁹ There is a Common System Modification Fee for systems under kW. See Docket DPU 26-57: <https://eeaaonline.eea.state.ma.us/dpu/fileroom/#/dockets/docket/12949>.

⁸⁰ Massachusetts DPU. "Long Term System Planning Tariff." Accessed June 13, 2026. <https://fileservice.eea.comacloud.net/V3.1.0/FileService.Api/file//afacbdjie?SV28oya3515g5uTEgbXIKcy0S/QxsWCL6MI4Qg87r4aPcSxI+blU344Khxm+qpOeg0hKFj9M9I/xQR8+/8GqPvdGgrFe6XR6nglfa80wd3rxFD8G4j981M2Rna9aVTXA>.

⁸¹ Massachusetts DPU. "Memorandum on the Joint Petition of Distribution Companies for Approval of Their Long-Term System Planning Process Proposal." May 8, 2026. <https://fileservice.eea.comacloud.net/V3.1.0/FileService.Api/file//afaidaie?pvS8c+JIEWoppK3a9Ut4g6qJ8gZlgGUjW1eLLBVZhYWPcSxI+blU344Khxm+qpOeg0hKFj9M9I/xQR8+/8GqPvdGgrFe6XR6nglfa80wd3rxFD8G4j981M2Rna9aVTXA>.

6.0 Minnesota

The Minnesota dockets described in this section are:

- Xcel Minnesota 2023 Integrated Distribution System Plan (Docket No. M-23-452) combined with the Minnesota’s Proactive Grid Upgrade Workgroup (Docket No. E002/M-24-318).
- Xcel Minnesota 2025 Integrated Distribution System Plan (Docket No. E-002/M-25-142) and Concurrent Proactive Upgrade Proposal.

Figure 3 shows a timeline of proactive-related developments in Minnesota.

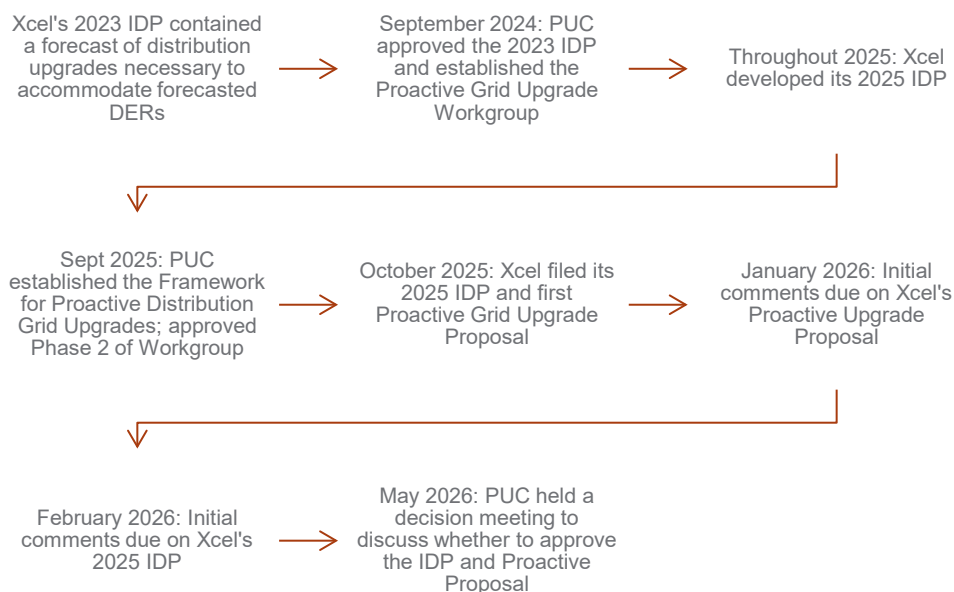


Figure 3. Timeline of proactive-related developments in Minnesota

6.1 Xcel Minnesota 2023 Integrated Distribution System Plan (Docket No. [M-23-452](#)) and Subsequent Proactive Distribution Grid Upgrade Workgroup ([E002/CI-24-318](#))

6.1.1 Background

- The 2023 energy omnibus bill in Minnesota (House file 2310), codified in state law (§ 216B.2425, subd. 9) required Xcel Energy’s 2023 Integrated Distribution Plan (IDP) to include “a forecast of necessary distribution upgrades to comply with various state statutes, an evaluation of how to reduce the cost of those upgrades using advanced technologies, and a discussion of potential cost allocation options.”⁸²

⁸² Minnesota PUC. “Notice Soliciting Stakeholder Members.” September 26, 2024. <https://efiling.web.commerce.state.mn.us/documents/%7BC0452F92-0000-CE12-AED7-A7BB3DD051CB%7D/download>.

- Xcel filed its 2023 IDP, which included its 2023 Transportation Electrification Plan, on November 1, 2023.⁸³ Xcel states that its distribution strategy is to “proactively invest in our distribution system so that capacity is available before our customers need it as well as prepare our system to accommodate increasing penetration of DERs.”
- In its IDP, Xcel proposed \$190 million for proactive hosting capacity upgrades for 2025-2028 to accommodate distributed generation necessary to meet state energy standards.⁸⁴ It did not identify specific uses for this funding and sought stakeholder and Commission feedback. Xcel also proposed \$132 million for its “Grid Reinforcement Program” which would undertake proactive upgrades to accommodate increased load growth.⁸⁵
- In May 2024, the Minnesota PUC approved Xcel’s 2023 Transportation Electrification Plan with modifications.⁸⁶
- In September 2024, the Minnesota PUC accepted Xcel’s 2023 IDP.⁸⁷ In November 2024, Xcel submitted an annual update of the IDP per the PUC’s 2020 Order in Docket No. E002/M-19-666.⁸⁸
- In the September 2024 Order, the Commission established the Proactive Grid Upgrade Workgroup to “develop a framework on cost allocation and proactive upgrades for Xcel,” with the goal of completing such work by July 2025.⁸⁹
- In April 2025, PUC Staff released a Draft Proactive Distribution Upgrade Framework and opened a comment period.
- In September 2025, the PUC issued an Order Establishing Framework for Proactive Distribution Grid Upgrades.⁹⁰ The workgroup participants suggested that the Commission adopt the proposed Framework, which they did. The Commission also approved the continuation of the workgroup for Phase 2 of framework development.

⁸³ Minnesota PUC. “Docket 23-453.” Accessed June 13, 2026.

<https://www.edockets.state.mn.us/Efiling/edockets/searchDocuments.do?method=showeDocketsSearch&searchType=new&userType=public>.

⁸⁴ Minnesota PUC. “2023 Integrated Distribution Plan.” November 1, 2023.

<https://efiling.web.commerce.state.mn.us/documents/%7BA07D8C8B-0000-CBCC-BD7D-801E5837A6BB%7D/download?contentSequence=0&rowIndex=123>.

⁸⁵ Ibid.

⁸⁶ Minnesota PUC. “Order Approving Xcel Energy’s 2023 Transportation Electrification Plan with Modifications.” May 9, 2024. <https://efiling.web.commerce.state.mn.us/documents/%7BA0085F8F-0000-CA1D-8953-628CAFD1F118%7D/download?contentSequence=0&rowIndex=57>.

⁸⁷ Minnesota PUC. “Order Accepting 2023 Integrated Distribution Plan and Modifying Reporting Requirements.” September 16, 2024.

<https://efiling.web.commerce.state.mn.us/documents/%7B90BDFB91-0000-C212-9EBA-FEC602C284D2%7D/download?contentSequence=0&rowIndex=37>.

⁸⁸ Minnesota PUC. “Compliance-Annual Update 2023 Integrated Distribution Plan.” November 1, 2024.

<https://efiling.web.commerce.state.mn.us/documents/%7B0076E992-0000-CA17-9D20-B729A1471D86%7D/download?contentSequence=0&rowIndex=30>.

⁸⁹ Minnesota PUC. “Notice Soliciting Stakeholder Members.” September 26, 2024.

<https://efiling.web.commerce.state.mn.us/documents/%7BC0452F92-0000-CE12-AED7-A7BB3DD051CB%7D/download>.

⁹⁰ Minnesota PUC. “Order Establishing Framework for Proactive Distribution Grid Upgrades.” September 2, 2025. <https://efiling.web.commerce.state.mn.us/documents/%7BB0730B99-0000-C61F-A8BE-972F8ACD8FA9%7D/download?contentSequence=0&rowIndex=13>.

- Some history: In the 2021 rate case, Xcel proposed \$12 million in capital additions to prepare for increased load growth from EVs and electrification. The program was found to be too speculative and was rejected by the Commission.

6.1.2 Proactive Definitions, Frameworks, or Rationales

- In the Proactive Distribution Upgrade Framework established by the Commission in September 2025, the following rationales are given for pursuing proactive upgrades: 1) enable customer DER and electrification adoption, 2) reduce or eliminate wait time to interconnect, 3) increased adoption speed of DERs, 4) avoid risk of construction and procurement bottlenecks, and 5) lifecycle cost reduction or overall spending efficiency.

6.1.3 New or Modified Methodologies

- In Xcel's 2023 IDP, they outline their distribution strategy, which is to "proactively invest in [the] distribution system so that capacity is available before ... customers need it as well as prepare [the] system to accommodate increasing penetration of distributed generation resources." They added, "We plan to do this by making investments in baseline capacity, improving asset health thereby decreasing reliability risk, and deploying industry leading technology solutions, both hardware and software, to maximize grid value while maintaining affordable rates for customers."⁹¹
- Also, in this IDP, Xcel refers to the need to prepare for the future by proactively planning for the next 30 years. To meet anticipated load growth during this timeframe, Xcel emphasized the need for more engineering employees "to design the uptick in capital projects," and to "ramp up ... resources with data analytics, project management and emerging technologies."
- Xcel has begun using LoadSEER in planning processes to illustrate long-term aggregate feeder peak load under different scenarios. It is a spatial forecasting tool that predicts how much, where, and when power must be supplied. Stakeholders have requested more information on the accuracy and precision of these forecasts. Fresh Energy proposes that Xcel consider using a 576-hour time series for load forecasting in an effort to expedite the inclusion of LoadSEER results into the company's capital investment plans.
- Fresh Energy suggests that the Commission direct Xcel to develop a low, medium, and high commercial and residential electrification forecast in the next IDP.
- Fresh Energy proposed two draft frameworks in their initial comments in this docket.⁹² They acknowledge that these ideas are not yet fully developed and will require further stakeholder discussions to agree on final approaches. First, they proposed an approach for thinking about the differences between cost allocation for interconnection upgrades and proactively planning for upgrades. The Cost Allocation and Proactive Construction Matrix shown in Figure 4, taken from their comments, illustrates how these concepts can be combined into several possible approaches which have different benefits and risks to different entities. In considering the role of proactive upgrades, Fresh Energy proposed four "pillars" that

⁹¹ Minnesota PUC. "2023 Integrated Distribution Plan." November 1, 2023.

<https://efiling.web.commerce.state.mn.us/documents/%7BA07D8C8B-0000-CBCC-BD7D-801E5837A6BB%7D/download?contentSequence=0&rowIndex=123>.

⁹² Minnesota PUC. "Xcel Energy's 2023 Integrated Distribution Plan: Fresh Energy Initial Comments." March 1, 2024.

<https://www.edockets.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId={5003FC8D-0000-CB16-9E11-62D8C339A246}&documentTitle=20243-204016-01>.

investments should meet, shown below. On both ideas, Fresh Energy sought feedback from other parties.

Fresh Energy's Cost Allocation and Proactive Construction Matrix⁹³

	Proactive Construction	Reactive Construction
Shared Costs	• Build distribution budgets around DER and electrification forecasts. • Assign incremental infrastructure costs via typical class cost allocation methods, e.g., in next rate case.	• Grid upgrades are made in response to individual customer requests. • Costs assigned via typical class cost allocation methods, e.g., in the next rate case.
Individually Allocated Costs	• Build distribution budgets around DER and electrification forecasts. • Individual customers, where appropriate, pay a fee to cover their share of the upgrade at the time of interconnection.	• Grid upgrades are made in response to individual customer requests. • Individual customers, where appropriate, pay a fee to cover their share of the upgrade at the time of interconnection.

Fresh Energy's Pillars for Proactive Upgrades⁹⁴

1. Useful: Proactive upgrades should be located in a relevant spot, needed, and useful. 2. Timely: Proactive upgrades should be reasonably certain of being useful within a specific period of time. 3. Efficient: Proactive upgrades that are recovered in base rates should be paired with programs that require or encourage efficient use of the grid (such as charging/discharging at preferable times to maximize utility of the infrastructure). 4. Equitable: The costs and benefits of proactive upgrades should be equitably distributed, and any upgrades recovers in base rates should prioritize projects serving under-resources customers or under-served areas of the system.
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Figure 4. Fresh Energy Proposed Four Pillars that Investments Should Meet

- In proactively planning investments in hosting capacity, the City of Minneapolis suggests that Xcel layer the hosting capacity map with equity indicators and with data obtained from local governments to determine where investments may be needed to support those goals and ordinances.
- In September 2024's acceptance by the PUC of Xcel's 2023 IDP, the PUC noted that it agreed with commenters that "additional record development is needed surrounding proactive grid upgrades and cost allocation," which requires a "stakeholder process to develop a framework on cost allocation and proactive upgrades for Xcel." The Proactive Grid Upgrade Workgroup was established to develop this framework. At a minimum, the PUC stated that the framework should address 1) how to allocate the costs of proactive upgrades; 2) how to ensure any proactive upgrades are distributed in an equitable manner

⁹³ Ibid.

⁹⁴ Ibid.

throughout a utility's service territory; 3) if costs are socialized among ratepayers, whether portions of the upgraded capacity should be reserved for certain customer classes; 4) how a proactive upgrade program would integrate with a utility's planned distribution investment programs; 5) how a utility's other capacity programs and changes to distribution standards impact available hosting capacity; 6) how to determine where and when there is a need for proactive upgrades using forecasted DER and load adoption; and 7) whether there should be changes to any of a utility's service policy provisions such as Contributions In Aid of Construction (CIAC).

- In Xcel's 2024 annual update to the 2023 IDP, Xcel emphasized that it is "continuing to proactively prepare the distribution grid to achieve three primary objectives: 1) address our aging assets; 2) enable the clean energy transition; and 3) modernize the grid."
- The Proactive Distribution Upgrade Framework, established by the Commission in September 2025 following the completion of Phase 1 of the Workgroup, contains the following notable approaches:⁹⁵
 - Establishes November 1 of odd-numbered years as the filing date for proactive upgrade proposals. The filing will happen in conjunction with the IDP, be evaluated in the same docket and process as the IDP but is not part of the IDP.
 - Requires a base case forecast and sensitivities that include higher and lower adoption of DERs and loads and requires Xcel to recommend which forecast should be adopted.
 - Requires a feeder and substation-level forecast for generation and peak load for all locations associated with proactive upgrades.
 - For each site where Xcel is proposing a proactive upgrade, they must provide a detailed set of information, including a quantitative or qualitative level of confidence of the forecasted need driving the need for the specific project.
 - A list of 15 criteria that each proactive upgrade proposal will be evaluated against, and on which Xcel must provide information for each proposal.
 - Creation of a "proactive cost-share window" which starts the year the upgrade project is placed in-service, lasting up to 10 years after the anticipated need date. Interconnecting customers that apply to interconnect on or before the window end date are deemed "proactive cost-share customers" and will pay "proactive cost-share fees."
 - Proactive cost-share fees act as an offset to the revenue requirements of all proactive distribution upgrades.
 - The fee shall be calculated at an aggregated, programmatic level for all approved proactive upgrade investments. Calculation: (total cost of all approved proactive upgrades)/(total kWac of capacity added by all approved proactive upgrades).
 - The Workgroup is directed to meet to refine and improve the Framework and resolve issues left out of Phase 1. Phase 2 of the Proactive Distribution Grid Upgrade Workgroup will address the following topics: 1) incorporation of front-of-the-meter-generation; 2) coordination and alignment with the reactive-DER Cost Sharing Program; 3) a Distributed Generation Engagement Group; 4) flexible interconnection; 5) Cost

⁹⁵ Minnesota PUC. "Order Establishing Framework for Proactive Distribution Grid Upgrades." September 2, 2025. <https://efiling.web.commerce.state.mn.us/documents/%7BB0730B99-0000-C61F-A8BE-972F8ACD8FA9%7D/download?contentSequence=0&rowIndex=13>.

Allocation and Cost Recovery Principles and Methodologies; 6) Capacity Reservation; and 7) Non-Location Specific Measures.⁹⁶

6.1.4 Summary of Issues or Concerns Raised

The issues listed below are summarized in the September 2024 Order accepting Xcel's 2024 IDP.⁹⁷

- Commenters generally agreed that additional record was necessary before taking further action on proactive upgrades.
- In the 2023 IDP, stakeholders raised a need for a better understanding of grid upgrades that would have a net revenue benefit for ratepayers and those that would make sense to be paid for over time by future interconnecting customers. Scenario analysis in the IDP could be “more well-rounded” if it also included a capital expense analysis. Integrating forecasting and capital investment plans is an area for continued discussion and iteration.
- There is concern that if proactive upgrades are based solely on forecasted adoption rates of electrified technologies, those investments will disproportionately serve higher-income areas.
- In its 2024 annual update to the 2023 IDP, Xcel highlighted that one notable change in its budget drivers was the addition wildfire mitigation investments. This inclusion is considered by Xcel to be a “proactive approach [that] helps reduce ignition risks and sustains or improves system reliability.”

6.2 Xcel Minnesota 2025 Integrated Distribution System Plan (Docket No. [E-002/M-25-142](#), [24-318](#)) and Concurrent Proactive Upgrade Proposal

6.2.1 Background

- Throughout 2025, Xcel held workshops for parties interested in the development of the 2025 IDP.
- In March 2025, Xcel invited interested parties to participate in a three-part workshop series on their Planned Net Loading methodology.⁹⁸ This was a result of Xcel's 2021 IDP, which instructed Xcel to “obtain input, and generate new ideas around a shared vision of the distribution grid of the future.”⁹⁹ Those workshops were held in April, May and July 2025.

⁹⁶ Terwilliger, Hanna. 2026. “Claritin for the Grid: Preventing Distribution System Congestion with Proactive Planning. ESIG Spring Technical Conference.” March 17, 2026. https://www.esig.energy/attachment/serve/esig-spring-technical-conference-mn-proactive-distribution-planning-3-17-2026_v2.

⁹⁷ Minnesota PUC. “Order Accepting 2023 Integrated Distribution Plan and Modifying Reporting Requirements.” September 16, 2024. <https://efiling.web.commerce.state.mn.us/documents/%7B90BDFB91-0000-C212-9EBA-FEC602C284D2%7D/download?contentSequence=0&rowIndex=37>.

⁹⁸ Minnesota PUC. “Planned Net Loading Workshop 1 Invitation.” March 18, 2025. <https://efiling.web.commerce.state.mn.us/documents/%7B30EFAA95-0000-C21C-92EA-E9E87EA16B81%7D/download?contentSequence=0&rowIndex=20>.

⁹⁹ Minnesota PUC. “Materials – Planned Net Loading Workshop 1.” May 9, 2025. <https://efiling.web.commerce.state.mn.us/documents/%7B0071B596-0000-C218-97BA-A68DE761A59F%7D/download?contentSequence=0&rowIndex=11>.

- In September 2025, Xcel provided the Minnesota PUC with IDP Preview Workshop materials from August 2025.¹⁰⁰
- On October 31, 2025, Xcel filed its 2026–2035 IDP¹⁰¹ and its first Proactive Grid Upgrade Proposal.¹⁰²
- Initial comments on Xcel’s Proactive Upgrade Proposal were due on January 28, 2026. Staff briefing papers were filed on April 23, 2026.¹⁰³ The Commission’s meeting on this proposal was held on May 7, 2026 and the order approving the first proposal was issued June 5, 2026.
- Initial comments on Xcel’s IDP were due on February 26, 2026.

6.2.2 Proactive Definitions, Frameworks, or Rationales

- According to Xcel’s August 2025 IDP workshop materials, a proactive upgrade is considered “a distribution upgrade made solely based on a forecasted need outside a utility’s traditional planning cycle.”
- According to Xcel’s IDP (2025), proactive distribution grid upgrades are “intended to address projected load growth and DER needs beyond the standard 5-year planning horizon. See Figure 5.

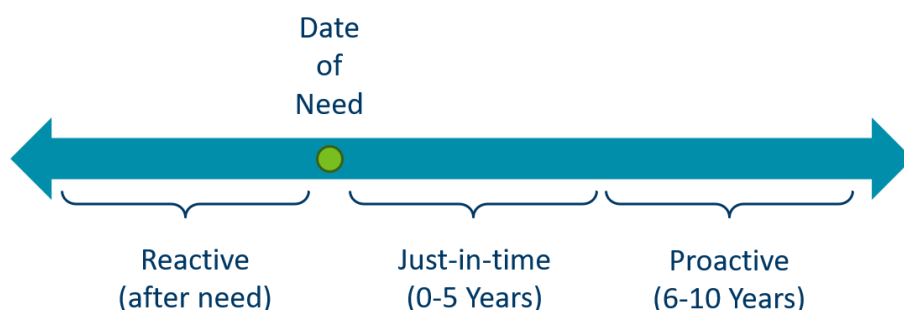


Figure 5. Minnesota Public Utilities Commission – What is Proactive Planning? (ESIG Spring Technical Conference, March 17, 2026)¹⁰⁴

- In more concise terms in Xcel’s IDP (2025), they consider proactive upgrades to “anticipate future system needs” and they “engineer solutions to meet [those needs].”

¹⁰⁰ Minnesota PUC. “Xcel Energy’s Integrated Distribution Plan Preview.” August 19, 2025. <https://efiling.web.commerce.state.mn.us/documents/%7BF0856399-0000-C915-85F3-53B2ABDEB1BA%7D/download?contentSequence=0&rowIndex=1>.

¹⁰¹ Minnesota PUC. “Integrated Distribution Plan 2026-2035.” October 31, 2025. <https://efiling.web.commerce.state.mn.us/documents/%7B60EC3B9A-0000-C414-B515-3DFC48F9802C%7D/download?contentSequence=0&rowIndex=92>.

¹⁰² Minnesota PUC. “Proactive Grid Upgrade Proposal.” October 31, 2025. <https://efiling.web.commerce.state.mn.us/documents/%7BF0EF3B9A-0000-C730-A6D8-34FED70C71BB%7D/download?contentSequence=0&rowIndex=97>.

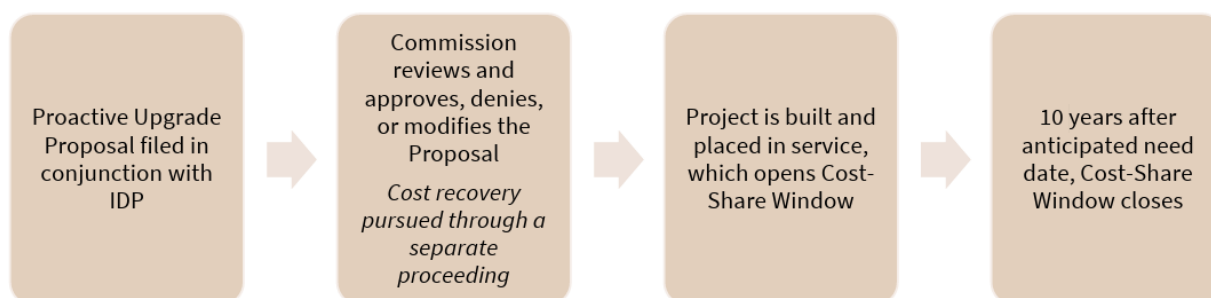
¹⁰³ Minnesota PUC. “Staff Briefing Papers for Docket No. E002/M-25-142.” May 7, 2026. <https://efiling.web.commerce.state.mn.us/documents/%7B30EDBA9D-0000-C216-A7C8-FFFF976E3E78%7D/download?contentSequence=0&rowIndex=7>.

¹⁰⁴ Terwilliger, Hanna. 2026. “Claritin for the Grid: Preventing Distribution System Congestion with Proactive Planning. ESIG Spring Technical Conference.” March 17, 2026. https://www.esig.energy/attachment/serve/esig-spring-technical-conference-mn-proactive-distribution-planning-3-17-2026_v2.

- In Xcel's Proactive Grid Upgrade Proposal (2025), they describe proactive upgrades as those that are planned and implemented in advance of forecasted capacity constraints instead of waiting for issues to arise to subsequently be addressed.¹⁰⁵ For example, they highlight that "proactive upgrades are especially important and beneficial ... helping to avoid future reliability issues and costly reactive solutions," especially in densely populated areas "where infrastructure expansion is especially challenging." Proactive upgrades are based on forecasted needs identified within a 5–10-year forecast," with the goal of addressing risks before they become urgent.
- Xcel lists several desired outcomes of proactive planning, including: "enabl[ing] DER and electrification adoption," "reducing interconnection wait times," "protect[ing] ratepayers through rigorous review of proactive investments," "maximiz[ing] system benefits while minimizing costs," and "anticipat[ing] adoption speed."

6.2.3 New or Modified Methodologies

- According to Xcel's August 2025 IDP workshop materials, a proactive upgrade is considered "a distribution upgrade made solely based on a forecasted need outside a utility's traditional planning cycle. In the context of this framework, the Proactive Distribution Upgrades submitted in the Proactive Upgrade Proposal would not be considered under existing distribution planning practices due to the proactive nature of the projects." They provided insight into their proposed process as shown in Figure 6.



Pro rata fees (\$/kW) collected from load and DER interconnections in proactively upgraded areas with an open Cost-Share Window

- Exemptions: Non-demand metered load customers and Priority Queue generation interconnections.

$$\text{Pro Rata Fee} = \frac{\text{Total cost of all approved Proactive Distribution Upgrades}}{\text{Total kW}_{AC} \text{ of capacity added by all approved Proactive Distribution Upgrades}}$$

Figure 6. Xcel's Proactive Distribution Upgrades Process¹⁰⁶

- The Proactive Distribution Grid Upgrade Framework enables Xcel to propose infrastructure investments that once approved, will be funded through a combination of pro rata payments from customers who use the new capacity (for a period of 10 years) and standard cost recovery from all customers. The Framework also "establishes a process for Xcel to invest proactively in the distribution system to create hosting capacity for DER and load before that capacity is needed."

¹⁰⁵ Minnesota PUC. "Proactive Grid Upgrade Proposal." October 31, 2025.

<https://efiling.web.commerce.state.mn.us/documents/%7BF0EF3B9A-0000-C730-A6D8-34FED70C71BB%7D/download?contentSequence=0&rowIndex=97>.

¹⁰⁶ Minnesota PUC. "Xcel Energy's Integrated Distribution Plan Preview." August 19, 2025.

<https://efiling.web.commerce.state.mn.us/documents/%7BF0856399-0000-C915-85F3-53B2ABDEB1BA%7D/download?contentSequence=0&rowIndex=1>.

- Xcel added that the proactive forecasted need period would be in mid-2030 to beyond 2035, following the end of its 5-year budget planning cycle between mid-2025 and mid-2030.
- Phase 2 of the Proactive Grid Upgrade Workgroup will address the remaining topics:
 - incorporation of front-of-the-meter generation
 - coordination with reactive DER cost sharing program
 - distributed generation engagement group
 - flexible interconnection
 - cost allocation and cost recovery principles and methodologies
 - capacity reservations
 - cost envelopes
 - non-location specific measures.¹⁰⁷

6.2.4 Summary of Issues or Concerns Raised

- In the November 2025 Notice of Comment Period, the PUC asked parties to comment on the following issues with respect to the proactive upgrade proposal:
 - Whether the proposal aligns with the Proactive Distribution Grid Framework
 - What type and amount of cost cap should the Commission establish for total Proactive Distribution Upgrade costs?
 - Should the Commission approve Xcel's tariff pages?
- With respect to the IDP overall, the PUC asked parties to comment on:
 - Whether Xcel addressed the Commission's IDP filing requirements and prior Orders
 - Forecasted distribution budget
 - Forecasting results and methodology
 - Proactive capacity investments
 - Updated Planned Net Loading methodology and risk analysis results
 - Targeted undergrounding proposal
 - Proposed cost-benefit analysis for discretionary investments
 - Non-wires alternatives analysis
 - Distributed Energy Resource Management Systems.

¹⁰⁷ Ibid.

- In response to Xcel's 2025 IDP, many comments were received. In February 2026, Xcel responded. Stakeholders proposed a \$15 million cost cap on investments made under the Proactive Distribution Grid Upgrade Framework, to which Xcel responded that this arbitrary cap "could unintentionally restrict the range of proactive investments" that the framework is intended to support. However, if a cap is imposed, Xcel argued that its implementation should wait until the framework has been implemented and Phase 2 discussions have begun.¹⁰⁸
 - Stakeholders also mentioned 1) customer cost-share fee methodology, 2) non-wires alternatives analysis, 3) requests for specific details (e.g., construction timing, load-growth triggers, cost-phasing, potential off-ramps, and permitting risks associated with proposed proactive upgrades), 4) load forecast retrospective, 5) the framework tariff sheet, and 6) reliability benefits.
 - In March 2026, Xcel responded to more comments from stakeholders. These included 1) planning process-related recommendations (e.g., expanding involvement in core engineering standards, forecasting methodologies, and system planning criteria), 2) cost-benefit analysis recommendations, and 3) retrospective forecast and project reporting recommendations.¹⁰⁹

¹⁰⁸ Minnesota PUC. "Reply Comments." February 18, 2026.

<https://efiling.web.commerce.state.mn.us/documents/%7B3045729C-0000-CB1F-8BD7-B271A4B874CF%7D/download?contentSequence=0&rowIndex=76>.

¹⁰⁹ Minnesota PUC. "Reply Comments – IDP." March 19, 2026.

<https://efiling.web.commerce.state.mn.us/documents/%7B20AC079D-0000-C715-831C-36632FD02FA9%7D/download?contentSequence=0&rowIndex=47>.

7.0 New Jersey

In this section, New Jersey’s proactive planning approaches contained in the Integrated DER Plans to Modernize the Electric Grid and Proactive System Upgrade Plans docket are described.

7.1 New Jersey’s Integrated DER Plans to Modernize the Electric Grid and Proactive System Upgrade Plans (Docket No. [QO24030199](#))

7.1.1 Background

- On May 23, 2018, New Jersey Governor Murphy signed Executive Order 28, which directed the Energy Master Plan Committee to complete an Energy Master Plan that would provide a comprehensive blueprint to achieve energy resource mix policy goals in New Jersey by 2050.¹¹⁰ An Energy Master Plan, completed in 2019, identifies several strategies to achieve New Jersey’s energy and emissions policy goals.¹¹¹ A follow-on Grid Modernization Report (Grid Mod Report) was approved by the New Jersey Board of Public Utilities (BPU) in November 2022.¹¹²
- A Grid Modernization Forum was formed by the NJBPU in response to recommendations in the Grid Modernization Report. The Grid Modernization Forum is comprised of expert workgroups to tackle barriers to increasing hosting capacity and grid flexibility.¹¹³ The first Grid Modernization Forum Workgroup, the Integrated Distribution and DER System Planning Workgroup, is focused on advancing the implementation of a formal requirement for “EDCs to file proactive plans outlining their intentions to evolve segments of the distribution grid into more adaptive and flexible distribution systems with higher DER hosting capacities.”¹¹⁴
- The Grid Flexibility Services Architecture Workgroup launched in April 2026, and a new, third workgroup – Cost Estimation Validation Allocation and Recovery (CEVAR) – is planned to launch in 2026 to get a better understanding of EDCs’ infrastructure upgrade costs and propose further amendments to interconnection rules (see N.J.A.C. 14:8-5). This is anticipated to involve alternative DER interconnection upgrade cost allocation approaches (besides cost-causer pays), such as a group study process.
- On January 20, 2026, New Jersey Governor Sherill signed Executive Order 2, declared a State of Emergency, and directed the BPU to take a “number of actions to ensure that electricity does not become an even greater financial burden for residents.”¹¹⁵

¹¹⁰ New Jersey Board of Public Utilities (BPU). “Straw Proposal – Proactive System Upgrade Planning Requirements.” May 8, 2026.

https://publicaccess.bpu.state.nj.us/DocumentHandler.ashx?document_id=1422894.

¹¹¹ New Jersey BPU. “2019 New Jersey Energy Master Plan: Pathway to 2050.” June 10, 2019.

https://s24.q4cdn.com/601515617/files/doc_downloads/2020/01/Final-2019-NJBPU-EMP.pdf.

¹¹² New Jersey BPU. “Grid Modernization Study: New Jersey Board of Public Utilities.” August 24, 2022.

<https://www.nj.gov/bpu/pdf/reports/NJBPU%20Grid%20Modernization%20Final%20Report.pdf>.

¹¹³ New Jersey BPU. “Integrated Distribution and DER Planning: Launch Notice.” June 5, 2024.

https://publicaccess.bpu.state.nj.us/DocumentHandler.ashx?document_id=1345187.

¹¹⁴ Ibid.

¹¹⁵ New Jersey BPU. “Request for Information.” February 3, 2026.

https://publicaccess.bpu.state.nj.us/DocumentHandler.ashx?document_id=1411021.

- The BPU responded with a request for information of the state’s four EDCs focusing on compliance with interconnection rules updates, identifying opportunities for the BPU to modify or waive existing regulations to improve efficiency and speed of interconnecting new projects, addressing how the company can improve hosting capacity maps, identifying constrained circuits within the company’s service territory that need to be upgraded to expedite interconnection, and addressing other means of supporting the development of DERs on constrained circuits.¹¹⁶ Early public comments supported “proactive upgrades” in areas with high DER development potential.¹¹⁷
- On April 29, 2026, the Integrated Distribution and DER System Planning Workgroup released a summary of their efforts, highlighting that they met on a bi-weekly basis between July 15, 2024 and December 16, 2025. The workgroup was tasked with advancing the “implementation of a formal requirement for the ... EDCs to file ... PSUP outlining their intention to evolve segments of the distribution grid into more adaptive and flexible distribution systems with higher DER hosting capacities.”¹¹⁸
- On May 8, 2026, BPU staff released the Proactive System Upgrade Plan (PSUP) Straw Proposal.¹¹⁹ BPU staff invited comments on the Straw Proposal with a deadline of May 29, 2026.

7.1.2 Proactive Definitions, Frameworks, or Rationales

- BPU staff highlight that the purpose of the PSUP “is to provide transparency into the EDC’s assessment of: the state of their distribution system in terms of system oversight, asset control, optimization, and DER dispatch; forecasted future DER penetration and load growth; potential expansion or upgrade project types to increase integration capacity or address other grid needs; what cost-effective or non-traditional distribution solutions are/were considered in lieu of or to complement traditional infrastructure investments; and the EDC’s plan to integrate load growth with generation by enabling DERs to participate in orchestrated virtual power plants, while reducing costs to New Jersey ratepayers.”¹²⁰
- BPU staff define PSUPs as “a comprehensive strategy that keeps the public informed and guides utilities in requesting approval for infrastructure investments (through traditional Rate Case and infrastructure improvement mechanisms) over a specified timeframe to meet the evolving needs of the distribution grid and seamlessly incorporate, manage, and optimize participating DERs.”¹²¹
- BPU staff refer to PSUPs as a policy tool that will qualitatively describe cost-effective 3- and 10-year distribution system strategies to:
 - Increase generation hosting and load-serving capacity for DERs and load growth from electric vehicle charging infrastructure and data centers

¹¹⁶ Ibid.

¹¹⁷ New Jersey BPU. “Public Comments on Docket No. QO24030199 – Grid Modernization and Integrated Distribution Planning.” February 2, 2026.

https://publicaccess.bpu.state.nj.us/DocumentHandler.ashx?document_id=1411038

¹¹⁸ New Jersey BPU. “Integrated Distribution and DER Planning: Launch Notice.” June 5, 2024.

https://publicaccess.bpu.state.nj.us/DocumentHandler.ashx?document_id=1421962.

¹¹⁹ New Jersey Board of Public Utilities (BPU). “Straw Proposal – Proactive System Upgrade Planning Requirements.” May 8, 2026.

https://publicaccess.bpu.state.nj.us/DocumentHandler.ashx?document_id=1422894.

¹²⁰ Ibid.

¹²¹ Ibid.

- Use DER Management Systems and other non-traditional solutions, such as Volt/VAR control and energy storage systems, to support the distribution system and increase distribution system utilization
- Enable DERs to form virtual power plants to improve distribution system operational flexibility and provide opportunities for grid service compensation.”¹²²
- BPU Staff emphasize that cost and rate recovery will be examined in separate proceedings.¹²³
- The PSUPs would be required to be filed by New Jersey EDCs and subsequently updated every 3 years thereafter, at minimum.¹²⁴

7.1.3 New or Modified Methodologies

- The PSUP Straw Proposal proposes that EDCs be guided by the following objectives for their PSUPs, as well as data and information requirements:
 - “Perform a Baseline Distribution System Assessment and identify current levels of distribution system utilization, DER asset visibility, and DER control and dispatch.”
 - Customer base data (e.g., a breakdown of their customer base by sector and rate classification type)
 - System data (e.g., asset health and condition, threat-based risk assessment, software and modeling, grid utilization metrics, worst-performing circuit analysis, asset management strategy, operations and programs, resource challenges)
 - Financial data (e.g., historical operations and maintenance and capital spending)
 - DER deployment (e.g., current DER deployment by type, size, and geographic dispersion.
 - “Forecast anticipated load and distributed generation growth and identify areas of the grid which are anticipated to have limited integration capacity.”
 - Baseline forecasting (e.g., load forecast methodology, projection of customer base, projection of gross load, assessment of load modifiers, granular locational forecasts, forecasted operations and maintenance and capital spending projections, forecasted workforce and material resources, anticipated changes to operations programs, resilience approach and planning)
 - Requirements of the scenario analysis (e.g., description of the methodologies used to develop two scenarios, including DER adoption rates, geographic deployment assumptions, expected DER load profiles, relevant regulations and legislation, and any other relevant assumptions, and identified grid needs, including a discussion of the processes and tools that would be necessary to accommodate the specified levels of DER generation and load integration for each scenario)
 - “Propose reliable and cost-effective non-traditional distribution system solutions to increase integration capacity, operational flexibility, and security to support customer generation and electrification needs.”

¹²² Ibid.

¹²³ Ibid.

¹²⁴ Ibid.

- Grid-Distributed Energy Resource Management Systems (e.g., project requirements of functions, scale, performance, and cybersecurity, systems integration requirements and data availability, and organizational and operational alignment with existing Distribution Management System/supervisory control and data acquisition)
- DER Registry (e.g., a plan for developing a DER registry, which must have a consistent structure across EDCs and have common data fields and definitions)
- Increase system capacity (e.g., description of how the EDC will increase integration capacity, smart inverters)
- Develop flexible interconnection and energization tariffs (e.g., describe plans and future steps toward the development of these tariffs and identify barriers to creating such tariffs)
- Resource planning (e.g., general organizational design and resource plan that corresponds to the 3- and 10-year distribution system evolution points, including key staffing positions and resource utilization intensity, and anticipated needs for future EDC, affiliate, and contractor personnel)
- Cost-effectiveness evaluation (e.g., spend prioritization, external funding opportunities, customer rate impacts by customer class, and cost-effectiveness of non-traditional distribution solutions)
- “Create avenues for DER participation and orchestration in a retail market and optimize DER value through advanced grid management capabilities.”¹²⁵

7.1.4 Summary of Issues or Concerns Raised

Many comments were submitted in response to the PSUP Straw Proposal and subsequently made available. Some are featured below.

- The NRDC, Environmental Defense Fund, Permit Power, and Evergreen Action collectively submitted comments.¹²⁶ They said the PSUPs contain several essential elements, including the need for “more strategic long-term distribution grid planning,” but argued that the Straw Proposal “falls short of the comprehensive, durable framework” necessary for New Jersey to reach its energy and climate goals. In addition, they stated that the proposal needs “a more robust review process that provides for cost recovery,” whether through an update to the PSUP structure or a general rate case to help drive utility action.
 - They asked that the BPU “clarify the role PSUPs will play in the broader regulatory framework” and said they “can and should be used as a platform to identify, and drive utilities toward a common set of best practices, inputs, and assumptions relevant to proactive system planning.” They recommended that they similarly follow New York PSC, which directed utilities to “seek uniformity on data, methods, and assumptions where possible and provide explanations of deviations when uniformity is not possible.”
 - The same stakeholders also commented that the Straw Proposal’s suggestion that PSUPs contain “high-level estimates of the costs and benefits associated ... with non-traditional solutions” is not likely to do them justice because of the level of detail

¹²⁵ Ibid.

¹²⁶ New Jersey BPU. “Docket No. QO2403011 – In the Matter of Developing Integrated Distributed Energy Resource Plans to Modernize New Jersey’s Electric Grid.” May 29, 2026.
https://publicaccess.bpu.state.nj.us/DocumentHandler.ashx?document_id=1424684.

required (e.g., hundreds of pages) that would make it more challenging for the BPU or other stakeholders to “meaningfully pressure-test the utilities’ analyses and results.”

- The Energy Efficiency Alliance of New Jersey stated overall support for the PSUPs but expressed concern about the risk of sensitive personal information being exposed as a result of the operational data required in the proposed DER registries, such as the “location and charging status of electric vehicles enrolled,” which could reveal the address of individual EV vehicle owners and indicate whether the owner is home or not.¹²⁷ Consequently, they suggest that the BPU integrate robust privacy protections to ensure only appropriate third parties and EDCs have access to such data.
- The New Jersey Utilities Association submitted comments on behalf of New Jersey’s four EDCs.¹²⁸ They expressed appreciation for the efforts to advance grid modernization objectives but stated that the PSUP deviates from the goal of the Integrated Distribution of DER workgroup, in which they participated, because some reporting requirements in the Straw Proposal “were not discussed or given due consideration” by the workgroup. They emphasized that these new requirements “impose significant administrative and analytical burdens on the EDCs without a clearly defined connection to the original objectives” of the workgroup, and warned that the associated costs of meeting these requirements could be passed onto ratepayers. In turn, they urged the BPU to “further evaluate which proposed filing requirements are necessary to facilitate proactive distribution planning and grid modernization, and to revise the PSUP Straw [Proposal] to limit filing requirements to information most directly relevant to achieving those objectives including affordability.”
 - They also recommended that the BPU “continue structured stakeholder engagement to evaluate the feasibility of proposed requirements, identify opportunities to streamline reporting obligations, and develop a common understanding of the framework’s objectives and expected outcomes.”
- Multiple commenters, including NRDC and Vote Solar, suggested that the BPU incorporate additional requirements in the PSUP related to equity (e.g., EDC spending based on location (in overburdened communities versus not in overburdened communities), shut-offs and service interruptions in overburdened communities, and other metrics).
- The New Jersey Division of Rate Counsel support the goal of the PSUP, which is “to plan cost-effective improvements to the distribution grid that make it more flexible, participatory, and equitable” but expressed several concerns.¹²⁹
 - They added that the PSUP is unclear in “how the increased utility spending ... will address the affordability crisis” and, generally, that the Straw Proposal “suffers from serious deficits and will not lead to the type of intended cost reductions the program is meant to achieve.”
 - They are critical of the Cost-Effectiveness Evaluation, which Staff had envisioned as a qualitative evaluation. Rate Counsel is concerned that this would not require EDCs to

¹²⁷ New Jersey BPU. “In The Matter of Developing Integrated Distributed Energy Resource Plans to Modernize New Jersey’s Electric Grid. Docket No. QO24030199.” May 29, 2026. https://publicaccess.bpu.state.nj.us/DocumentHandler.ashx?document_id=1424690.

¹²⁸ New Jersey BPU. “In The Matter of Developing Integrated Distributed Energy Resource Plans to Modernize New Jersey’s Electric Grid. BPU Docket No. QO24030199.” May 29, 2026. https://publicaccess.bpu.state.nj.us/DocumentHandler.ashx?document_id=1424866.

¹²⁹ New Jersey BPU. “Comments on Straw Proposal for Proactive System Upgrade Planning Requirements.” June 5, 2026. https://publicaccess.bpu.state.nj.us/DocumentHandler.ashx?document_id=1425555.

quantify either costs or benefits, leaving ratepayers without a meaningful opportunity to challenge cost-effectiveness at the stage where planning decisions are made. Public Service Electric and Gas Company also noted the need for methodological rigor in the benefit cost analysis framework, such as common definitions for “cost elements, benefit categories, data sources, and key assumptions.”¹³⁰

- They conclude that “a well-designed PSUP framework and proactive distribution planning, when done right, can lower long-term system costs and accelerate DER integration to the benefit of all New Jersey ratepayers. Rate Counsel’s comments are not opposition to this concept, but our comments throughout this docket and as evidenced above point out the glaring truth: the current proposed framework does not achieve the type of procedural safeguards and analytical rigor that ratepayer protection requires.”
- Finally, Rate Counsel is concerned that, as written, the PSUP review process would create a strong presumption of prudence that will effectively collapse the formal distinction between planning and cost recovery. They recommend that the BPU require that any cost recovery filing premised on a PSUP be proposed through a base rate case and accompanied by a prudence certification as has traditionally been required.

¹³⁰ New Jersey BPU. “In the Matter of Developing Integrated Distributed Energy Resource Plans to Modernize New Jersey’s Electric Grid.” May 29, 2026.
https://publicaccess.bpu.state.nj.us/DocumentHandler.ashx?document_id=1424682.

8.0 New York

The following New York activities are described in this section:

- Three enabling, context-setting legislative/regulatory actions:
 - Climate Leadership and Community Protection Act (CLCPA, Chapter 106 of the Laws of 2019)
 - Advanced Clean Trucks Regulation adopted by the New York Dept of Environmental Conservation in 2021 (6 NYCRR Subpart 218-4)
 - Zero-emission vehicle mandate signed into law in 2022.
- Barriers to Medium- and Heavy-Duty (MHD) Electric Vehicle Charging Infrastructure (CASE 23-E-0070).
- Proactive Planning for Upgraded Electric Grid Infrastructure (Case 24-E-0364). See Figure 7.

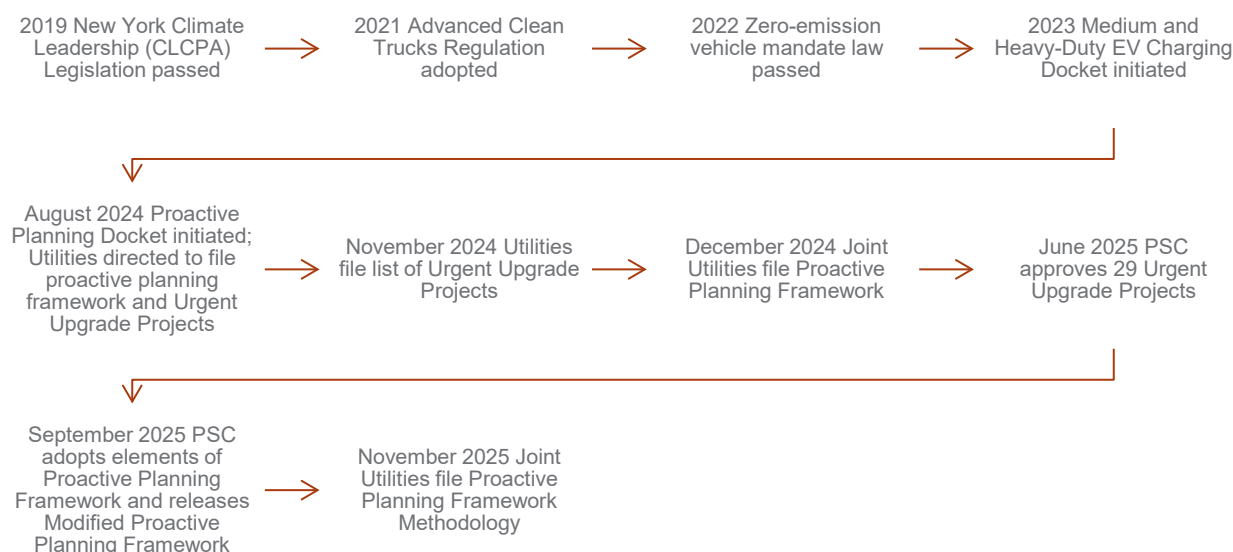


Figure 7. Timeline of Proactive-Related Developments in New York (2019–2025)

8.1 Enabling Legislation and Regulation

The following three pieces of legislation paved the way for the current proactive planning and investment activities in New York.

- 2020 – Accelerated Renewable Energy Growth and Community Benefit Act. The Act told utilities to submit plans for investments that are required to comply with the energy directives in the CLCPA (2019).

- 2019 – CLCPA, Chapter 106 of the Laws of 2019. The CLCPA codified requirements that drive all subsequent EV and medium- and heavy-duty vehicle (MHDV) regulatory activity.¹³¹
- 2021 – Advanced Clean Trucks Regulation adopted (6 NYCRR Subpart 218-4). New York State adopted California's Advanced Clean Trucks Regulation in December 2021, setting mandatory zero-emission vehicle sales requirements for MHDV manufacturers. This regulation became a key driver cited in PSC proceedings.¹³²
- 2022 – Zero-Emission Vehicle mandate signed into law. Governor Hochul signed a law requiring all sales of new passenger cars and trucks in the state to be zero emission by 2035. The MHDV sector is included in that law, with a 2045 target.¹³³

8.2 New York Public Service Commission, Motion of the Commission to Address Barriers to Medium- and Heavy-Duty Electric Vehicle Charging Infrastructure ([CASE 23-E-0070](#))

8.2.1 Background

- The New York PSC initiated this case in April 2023 with an explicit focus on proactive investment: “This includes addressing barriers to the efficient and timely development of the charging infrastructure and considering revisions to utility planning process for proactive investment in EV infrastructure, particularly in high-priority locations.”¹³⁴
- In initial comments filed in June 2024, the Joint Utilities proposed a framework that included identifying concentrated loads, developing a proactive infrastructure investment plan, and authorizing recovery of costs of investments made.¹³⁵
- The Joint Utilities argue that areas with load constraints and a high confidence of future demand should be prioritized for proactive investments.¹³⁶
- In May 2024, the New York Department of Public Service (DPS) hosted the Electric School Bus Technical Conference. This was part of the state's efforts to support “proactive planning for utility infrastructure supporting vehicle electrification.”¹³⁷

¹³¹ New York Public Service Commission (NY PSC). “New York Electric Vehicle Infrastructure Make-Ready Program.” January 12, 2024.

<https://jointutilitiesofny.org/sites/default/files/JU%20EVs/January%202024%20update/JU%20Make-Ready%20Program%20Participant%20Guide.pdf>.

¹³² NY State Department of Environmental Conservation. “Heavy Duty Vehicles.” Accessed July 2, 2026. <https://dec.ny.gov/environmental-protection/air-quality/controlling-motor-vehicle-pollution/heavy-duty-vehicles>.

¹³³ Walton, Robert. “Customer and conservation groups urge New York regulators to tackle medium- and heavy-duty EVs.” May 31, 2022. <https://www.utilitydive.com/news/nrdc-new-york-psc-medium-heavy-electric-vehicle-ev/624438/>.

¹³⁴ <https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={40F19F87-0000-CE10-B9FC-579FE87EB823}>

¹³⁵ NY PSC. “Case 23-E-0070: Proceeding on Motion of the Commission to Address Barriers to Medium- and Heavy-Duty Electric Vehicle Charging Infrastructure.” April 20, 2023. <https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={20FE8C88-0000-CF1D-B046-563200EBE36C}&DocTitle=JU%20MHDV%20Initial%20Response>.

¹³⁶ Ibid.

¹³⁷ NY State Department of Public Service. “NYS Electric School Bus Technical Conference: Case 23-E-0070.” May 31, 2024. <https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={00FCDE8F-0000-C43B-9BBE-D5A7B385DCB6}&DocTitle=Full%20ESB%20Tech%20Conference%20Presentation>.

- In December 2024, New York State Energy Research and Development Authority (NYSERDA) presented a slide deck regarding medium- and heavy-duty EV grid impact and investment study findings.¹³⁸ Elements of the study are shown in Figure 8.

MHD VEHICLE ANALYSIS OVERVIEW

Clean Transportation is conducting an **MHDV market analysis** on behalf of the Department of Public Service (DPS) and the Public Service Commission (PSC) to bolster their **proceedings related to Medium and Heavy-Duty Vehicles**.

Four Categories of Work			
Category 1: MHD ZEV Market Overview - Stakeholder Outreach - Barriers to truck and bus electrification - Market overview (model availability, technologies, infrastructure & incentives)	Category 2: MHD ZEV Adoption & Charging - Forecasting vehicle adoption, charging, & grid loads associated with MHD vehicles - Reviewing mandates and policy targets to identify make-ready needs	Category 3: MHD EV Make-Ready BCA - Benefit-Cost Analysis and ratepayer impact analysis of an MHD EV make-ready program - Determine reasonableness of ratepayer cost recovery	Category 4: Proactive Planning Support - Provide modeling for efforts that arise throughout the proceeding - Build on Categories 1-3 as needed to address future questions
Complete	Complete	Started	In Progress

Figure 8. Four Categories of MHDV Work¹³⁹

- In April 2026, NYSERDA again filed a presentation to this docket from an April 9, 2026, webinar where NYSERDA presented the findings of a NYSERDA MHD EV Grid Impact and Investments Study–MHD Make Ready Analysis.¹⁴⁰
- There are four workstreams in the Clean Transportation MHDV market analysis being conducted on behalf of New York DPS and the PSC to bolster the proceedings related to MHDVs. Figure 8 shows the status of the study as of April 2026.¹⁴¹

8.2.2 Proactive Definitions, Frameworks, or Rationales

- The Commission defined proactive planning as anticipating the location and magnitude of future electrification load and identifying high-priority infrastructure upgrades before capacity problems arise rather than reacting to individual customer service requests after the fact.¹⁴²
- The Commission identified MHDVs as presenting a uniquely challenging planning problem due to their high-capacity chargers (potentially exceeding 1 MW), clustering behavior at depots and highway corridors, and the accelerating mandates of both the CLCPA and the

¹³⁸ NYSERDA. “NYSERDA MHD EV Grid Impact & Investment Study: MHD Make Ready Analysis.” December 11, 2024.

<https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={F028BD94-0000-C330-898B-2A708D11A377}&DocTitle=MHD%20Make%20Ready%20Analysis%20Presentation>.

¹³⁹ Ibid.

¹⁴⁰ NYSERDA. “NYSERDA MHD EV Grid Impact & Investment Study: MHD Make Ready Analysis.” April 9, 2026. <https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={4027B59D-0000-CB23-B536-D5CA90B7E340}&DocTitle=April%209%20Webinar%20Presentation%20Materials>.

¹⁴¹ Ibid.

¹⁴² NY PSC. “Case 23-E-0070: Proceeding on Motion of the Commission to Address Barriers to Medium- and Heavy-Duty Electric Vehicle Charging Infrastructure.” April 20, 2023. <https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={40F19F87-0000-CE10-B9FC-579FE87EB823}&DocTitle=Order%20Instituting%20Proceeding%20and%20Soliciting%20Comments>.

Advanced Clean Trucks regulation. The conventional reactive planning model was deemed insufficient to keep pace.¹⁴³

- The Order introduced the concept of identifying "hotspots" (i.e., concentrations of existing depots, high-traffic destinations such as highway rest areas, and future-proofed hub locations) as the organizing framework for where proactive infrastructure investment should be directed.¹⁴⁴
- The Commission directed that proactive planning prioritize Disadvantaged Communities and Clean Air Act non-attainment areas, which bear a disproportionate share of diesel truck and bus pollution.¹⁴⁵

8.2.3 New or Modified Methodologies

- In the initiating order in this case, the Commission indicated that the proceeding is being initiated to consider a comprehensive framework to identify and address what immediate and long-term actions will best support MHDV market growth. The proceeding also was anticipated to develop proactive planning approaches to ensure grid infrastructure is prepared to enable the growing EV charging needs across New York.¹⁴⁶
- In a November 2023 technical conference, the Joint Utilities proposed guiding principles for a proactive planning framework and process:¹⁴⁷
 - Enable flexibility and speed for more nimble grid planning
 - Mitigate costs and risks of investments
 - Engage the right stakeholders.
- The Joint Utilities also proposed that the proactive investment proposals should contain:¹⁴⁸
 - Load projections utilizing a methodology to determine future load
 - Work scope, cost, and timeline of investment needs
 - Proposal evaluations that include the alternatives considered, risks of inaction or delay, multi-value benefits of investments, and alignment with other planning processes.
- The Commission directed the staff to submit a whitepaper with recommendations for the Commission's consideration for public comment. This has not yet been released. The need for the white paper may have been replaced and subsumed by the activity in the [Case 24-E-0364](#) (see discussion below).

¹⁴³ Ibid.

¹⁴⁴ Ibid.

¹⁴⁵ Ibid.

¹⁴⁶ Ibid.

¹⁴⁷ National Grid and Con Edison. "EV Proactive Planning Studies: Technical Conference Presentation." November 2, 2023. <https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={D014A58B-0000-C635-BB67-63DF8C34A7FF}>.

¹⁴⁸ Ibid.

- The April 2026 NYSEDA webinar presented results of a Medium and Heavy Duty Grid Impact and Investments Study – MHD Make Ready Analysis, which included a presentation of 1) EV adoption scenarios; 2) charging port counts by power level and location (i.e., home, depot, enroute), and 3) load shapes for the timeframe 2025–2035.¹⁴⁹
- Three adoption scenarios are presented for EVs. A central case reflecting vehicles covered by Advanced Clean Truck regulation, school bus fleet requirements, and transit bus fleet targets. Two sensitivity cases that include early or delayed scenarios. These sensitivities shift State Energy Plan adoption curve by ± 2 years. The study modeled three charging locations:
 - Private residence
 - Depot (also known as “return-to-base” charging) – charging in which a vehicle is stored overnight
 - Enroute – charging in which a vehicle is enroute to a destination. Note: these locations typically require “fast” charging.

8.2.4 Summary of Issues or Concerns Raised

- There has been some disagreement and discussion around how to prioritize areas for investments.
- A proactive planning framework, which deviates from the traditional regulatory model for utility spending and cost recovery, comes with potential costs and risks for ratepayers that the Commission will have to balance.¹⁵⁰
- In a variety of different comments filed to the docket, parties raised the issue of protecting ratepayers and ensuring accountability for utilities through things like targets, metrics and reporting, or performance incentive mechanisms.
- In NYSEDA's December 2024 presentation, they provided recommendations for regulators and utilities, drawn from their stakeholder survey. One recommendation called for “identifying and addressing zoning policies that impede fleets’ ability to install and/or use high voltage/high power electrical equipment [because it] is an important way to *proactively* support fleets’ planning process” (emphasis added).¹⁵¹

¹⁴⁹ NYSEDA. “NYSEDA MHD EV Grid Impact & Investment Study: MHD Make Ready Analysis.” April 9, 2026. <https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={4027B59D-0000-CB23-B536-D5CA90B7E340}&DocTitle=April%209%20Webinar%20Presentation%20Materials>.

¹⁵⁰ NY PSC. “Comments of the Vehicle-Grid Integration Council (VGIC) on Proactive Planning and V2X.” February 27, 2024. <https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={70ADF08D-0000-C118-AFAF-A1C536C2DBDB}&DocTitle=VGIC%20Proactive%20Planning%20and%20V2X%20Comments>.

¹⁵¹ NYSEDA. “NYSEDA MHD EV Grid Impact & Investment Study: MHD Make Ready Analysis.” December 11, 2024. <https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={F028BD94-0000-C330-898B-2A708D11A377}&DocTitle=MHD%20Make%20Ready%20Analysis%20Presentation>.

8.3 Proactive Planning for Upgraded Electric Grid Infrastructure – New York Public Service Commission Order and Framework (Case 24-E-0364)

8.3.1 Background

- In August 2024, the New York PSC commenced a proceeding “to evaluate new energy loads from transportation and building electrification to proactively identify and develop future grid infrastructure needs.” As part of this effort, they directed IOUs “to develop a framework for proactively planning for infrastructure needs driven by transportation and building electrification, and to determine how to address today’s urgent infrastructure needs.” This proactive planning framework will complement and integrate with New York PSC’s Coordinated Grid Planning Process (CGPP), which merges transmission and distribution upgrade needs with EV planning.¹⁵²
- In the August 2024 Order, the New York PSC also noted that it will take time to develop an integrated planning process and conduct studies and receive regulatory approvals, so the Commission established a process to address urgent upgrade projects while the statewide proactive planning framework is developed. New York utilities were directed to submit filings in three months, by November 2024, outlining urgent upgrades required in their territories. They were directed to file in four months, by December 2024, describing the needed long-term planning processes.¹⁵³
- In November 2024, each major utility submitted its own Urgent Upgrades filing. Filings were developed by the Joint Utilities independently and collectively, and filed separately at the New York PSC.
- In December 2024, several utilities in New York filed the Joint Utilities Proactive Planning Framework (referred to as the “Framework Filing”).¹⁵⁴
- In June 2025, the New York PSC approved 29 Urgent Upgrade projects valued at \$636.2 million that will enable 642 MW of electrification upgrades, which will help accelerate decarbonization of the transportation and building sectors. This action was “taken under the Commission’s innovative proceeding on proactive planning for upgraded electric grid infrastructure.”¹⁵⁵ Note: these projects were approved prior to the investment framework being approved by the New York PSC.
- Utilities started submitting quarterly update reports on urgent upgrade projects in September 2025. They also submitted quarterly reports in December and March 2026.

¹⁵² NY PSC. “Commission Announces New Proactive Grid Planning Proceeding to Prepare New York’s Electric Grid for Building and Vehicle Electrification.” August 15, 2024. <https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={80B45791-0000-CF1C-9E64-1BAE60F1B35C}&DocTitle=PRESS%20RELEASE%20-%20Commission%20Announces%20New%20Proactive%20Grid%20Planning%20Proceeding%20to%20Prepare%20New%20York%20BFs%20Electric%20Grid%20for%20Building%20and%20Vehicle%20Electrification>.

¹⁵³ Ibid.

¹⁵⁴ NY PSC. “Joint Utilities’ Long-Term Proactive Planning Framework.” Accessed July 2, 2026. <https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={60C3C193-0000-C42C-9162-2B10D1624579}&DocTitle=Joint%20Utilities%20Proactive%20Planning%20Framework%20Filing>.

¹⁵⁵ NY PSC. “PSC OK’s Critically Needed Infrastructure Projects.” June 12, 2025. <https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={10206597-0000-C337-9B7F-BFC30DADA012}&DocTitle=PRESS%20RELEASE%20-%20PSC%20OK>.

- In September 2025, the New York PSC adopted various components of the utilities' Framework Filing, with modifications, and directed the utilities to complete analysis and stakeholder engagement described in the Order.¹⁵⁶ Next steps were identified as utilities filing "detailed plans providing an outline of the data needs and assumptions required to develop granular load forecasts," followed by a "study to identify the grid needs driven by electrification, economic development and distributed energy resources."¹⁵⁷
- In November 2025, New York utilities submitted the Joint Utilities' Proactive Planning Framework Methodology document in response to the September 2025 PSC order.¹⁵⁸ This revised Framework Methodology details "data needs, related input assumptions, and the process for developing granular load assessments which will inform planning activities in the first Proactive Planning cycle."

8.3.2 Proactive Definitions, Frameworks, or Rationales

- Neither the September 2025 PSC order nor the November 2025 utility methodology document appears to directly define "proactive" planning/investment as compared to traditional planning/investment. The utility methodology defines "proactive planning load assessments" as augmenting existing forecasts with granular data to "identify needs on the grid driven by transportation or building electrification, economic development, and/or DER interconnection."¹⁵⁹
- The September 2025 order states: "This generic proceeding has allowed a depth and breadth of analysis and stakeholder engagement on this important topic that would be more difficult to achieve through individual utility rate case proceedings. Furthermore, this proceeding has allowed the integration of all the utilities in a single process of design and improvement. In the spirit of state-wide unification, the Commission directs all of the utilities to utilize the Modified Framework laid out below, following a common method and a common timeline, to provide a single source of information to the Commission and stakeholders regarding grid needs arising due to electrification."¹⁶⁰
- In the Joint Utilities Proactive Planning Framework (Dec 2024), New York utilities proposed a proactive planning process guided by five principles: 1) support customer needs in a timely manner without adverse impacts; 2) support achievement of objectives in policies,

¹⁵⁶ NY PSC. "Order Adopting Modified Proactive Planning Framework." September 18, 2025.

<https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B80185E99-0000-CF1D-A57E-F4A6874B79D5%7D>.

¹⁵⁷ NY PSC. "Commission Advances New Proactive Grid Planning Proceeding to Prepare New York's Electric Grid for Building and Vehicle Electrification." September 18, 2025.

<https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={30125E99-0000-C138-BAFC-D3F759F86FEC}&DocTitle=PRESS%20RELEASE%20-%20Commission%20Advances%20New%20Proactive%20Grid%20Planning%20Proceeding%20to%20Prepare%20New%20York%20C2%BFs%20Electric%20Grid%20for%20Building%20and%20Vehicle%20Electrification>.

¹⁵⁸ NY PSC. "The Joint Utilities' Proactive Planning Framework Methodology Document." Accessed July 2, 2026. <https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={5050989A-0000-C111-99D7-93D1166162F9}&DocTitle=Revised%20Proactive%20Planning%20Framework%20Methodology%20Document>.

¹⁵⁹ Ibid.

¹⁶⁰ NY PSC. "Order Adopting Modified Proactive Planning Framework." September 18, 2025.

<https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={80185E99-0000-CF1D-A57E-F4A6874B79D5}&DocTitle=Order%20Adopting%20Modified%20Proactive%20Planning%20Framework>.

laws, and regulations; 3) cost efficiency; 4) flexible planning and authorization; and 5) complement other regulatory processes.¹⁶¹

8.3.3 New or Modified Methodologies

8.3.3.1 Urgent Upgrades Process

- The initiating order in the proactive planning docket in August 2024 created a separate expedited process for Urgent Upgrade Projects that require action sooner than the broader Proactive Planning Process. Urgent Upgrade projects are those electrification-driven upgrades that require short-term action before and outside of the Proactive Planning Process, either because of load growth expectations or construction timelines. The PSC defined this category to include utility upgrades that must begin construction before mid-2026. The Commission directed utilities to submit filings within three months outlining urgent upgrades required in their service territories, and a separate filing within four months describing the needed long-term planning process.¹⁶²
- There are four evaluation criteria for projects to be considered urgent upgrade projects. They are:¹⁶³
 1. The upgrade is necessary to enable anticipated load associated with transportation electrification and/or building electrification.
 2. Construction-related activities must commence by July 1, 2026.
 3. High degree of certainty of need based on location, magnitude, and timing of need.
 4. Appropriate sizing and risk/benefit analysis.
- Utilities filed projects in November 2024 and in June 2025, the commission approved projects totaling \$632.2 million dollars. Con Edison received approval for five of their originally proposed nine projects, totaling \$439.9 million for 380 MW of new capacity, including a significant expansion at Zerega Avenue to enable fleet electrification and a redesign of the Hunt's Point electrical system. National Grid received approval for 22 of its proposed 46 projects in its upstate territory, totaling \$126 million for 184.8 MW of new capacity, including innovative deployments of grid-enhancing technology such as mobile energy storage devices for near-term high-power charging on major Thruway corridors. New York State Electric and Gas (NYSEG) and Rochester Gas and Electric (RGE) received approval for two of their ten proposed projects, with total capital costs of \$37.1 million and \$33.2 million for projects in NYSEG's and RGE's service territories, respectively.
- Utilities must file quarterly and end-of-project status reports. The August 2024 order outlines cost recovery mechanisms that utilities must follow for urgent project upgrades needed to meet policy goals. They also must file updated reports if any of the authorized projects are stopped or paused for more than 90 days. Quarterly update reports must include the following information, at a minimum, for each of the projects authorized in this order:

¹⁶¹ NY PSC. "Joint Utilities' Long-Term Proactive Planning Framework." Accessed July 2, 2026. <https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={60C3C193-0000-C42C-9162-2B10D1624579}&DocTitle=Joint%20Utilities%20Proactive%20Planning%20Framework%20Filing>.

¹⁶² NY PSC. "Order Establishing Proactive Planning Proceeding." August 15, 2024. <https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={80465791-0000-C51E-B4A0-7B56E347E0F5}&DocTitle=Order%20Establishing%20Proactive%20Planning%20Proceeding>.

¹⁶³ NY PSC. "Order Addressing Urgent Upgrade Filings." June 12, 2025. <https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BF05F6597-0000-C17B-B068-916CB5B91D67%7D>.

- Budget changes or cost overruns
- Schedule changes, including estimated in-service dates, and the reason for the changes
- Comparison of the original projected budget and the actual capital expenditures, and the reason for any differences
- Estimated total quantity of work completed under the projects. In the event that the work cannot be quantified, major tasks completed shall be provided
- Comparison of the projected and actual in-service date
- Upon project completion, a brief report on each completed project with details on lessons learned, how any deviations on project timing, equipment procurement, costs, and risks were addressed, and how updated loads and load forecasts align with those found in the initial project proposal.

8.3.3.2 Cost Recovery for Urgent Upgrade Projects

- Because urgent upgrade projects were identified as necessary to further New York's effort to electrify the transportation and building sectors, the New York PSC determined that it was appropriate to provide the Joint Utilities recovery of the costs associated with these investments once they are placed into service. Depending on the timing of investments, surcharges were authorized for some utilities. National Grid was approved to implement a surcharge until investments can be reflected in base rates. Surcharges can include:
 - Return on capital investments (including cost of removal)
 - Depreciation expense
 - Incremental operating expenses associated with capital expenditures for the urgent upgrade projects.
- National grid surcharge recoveries are initially allocated to service classes based on using the appropriate transmission and demand allocators as contained in the utility's most recent cost of service study. Amounts are to be recovered on a per kWh basis for non-demand billed customers, on a per-kilowatt basis for demand billed customers, and on an as-used demand basis for standby service customers and optional demand service customers.
- Con Edison's proposed projects were 4 and 6 years from the time of the Commission's June 2025 order, so the Commission determined that a surcharge mechanism was not necessary. Costs associated with the urgent upgrade projects can be reflected in the company's pending rate proceeding and in future rate proceedings. However, in the event the urgent upgrade projects end up being placed into service prior to them being fully reflected in base rates, Con Edison is authorized to make a tariff filing to implement a surcharge mechanism to recover the return of the asset, or depreciation, and the return on the investment of the projects until such time that they are fully reflected in base rates.
- NYSEG and RGE are in the same situation as Con Edison, with in-service dates of 2028 and 2029, making the surcharge unnecessary. The costs associated with these projects can be reflected in a future rate proceeding prior to the estimated in-service dates of these projects.
- The Commission denied NYSEG and RGE's request to recover 100% of construction work in progress in rate base while the projects are in construction and to accelerate the depreciation of the urgent upgrade assets.

8.3.3.3 Proactive Planning Framework

- In the initiating order in this docket, in August 2024, the New York PSC directed the New York utilities to file a framework for proactively planning for infrastructure needs driven by transportation and building electrification.¹⁶⁴ In the Joint Utilities Proactive Planning Framework (Dec 2024), New York utilities proposed a four-stage process for proactive planning, which included: 1) load assessment; 2) planning and solution design; 3) project eligibility and prioritization criteria; and 4) proposal and authorization of eligible projects. Combined, the four stages comprise the proactive planning process “cycle.”¹⁶⁵
- In the Joint Utilities Proactive Planning Framework (Dec 2024), New York utilities proposed the following criteria for determining proactive planning project *eligibility*:
 1. Upgrade required to support electrification: “demonstrate that an upgrade to serve anticipated electrification load from transportation, buildings, industrial load, or economic development. Eligible projects will include those enabling achievement of laws and regulations requiring electrification.”
 2. Need to begin construction related activities urgently: “demonstrate that Construction-related Activities must commence within 18 months of filing date (i.e., before approval of projects in the next Proactive Planning Cycle) to avoid the risk of delay for customer electric load connection.”
- They also established project *prioritization* criteria: degree of certainty, consideration of risks and benefits, alignment with state law objectives, qualitative or quantitative benefits, costs, availability of alternatives, locations or site types, and project timelines and financials.
- The Joint Utilities' initial framework submission fell short of fully addressing the planning process outlined in the PSC's Initiating Order. In response, the Commission required the utilities to submit a Proactive Planning Framework Methodology Document detailing data requirements, underlying assumptions, and methodology for building the granular load assessments that will underpin the first planning cycle. The PSC also noted that utilities are not at a uniform level of maturity when it comes to forecasting and planning for electrification-driven and other forms of load growth, such as economic development. To address this, the Commission has set a clear expectation: utilities must aggressively advance and harmonize their approaches so that, by the conclusion of the first Proactive Planning cycle, a common and consistent study methodology is in place across all utility service territories.
- In the September 2025 Order Adopting Modified Proactive Planning Framework, the New York PSC highlighted that the “primary driver of transmission and distribution system needs due to electrification associated with building, transportation, and economic development is the size, timing, and specific location of the new loads,” which means that attention “must be given to forecasting such loads and collecting other pertinent data.” Traditional methods, such as “simple ratios or estimates to downscale transmission system-wide forecasts to nodes,” they emphasize, “are no longer sufficient.” This is because these traditional

¹⁶⁴ NY PSC. “Order Establishing Proactive Planning Proceeding.” August 15, 2024.
<https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={80465791-0000-C51E-B4A0-7B56E347E0F5}&DocTitle=Order%20Establishing%20Proactive%20Planning%20Proceeding.>

¹⁶⁵ NY PSC. “Joint Utilities’ Long-Term Proactive Planning Framework.” Accessed July 2, 2026.
<https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={60C3C193-0000-C42C-9162-2B10D1624579}&DocTitle=Joint%20Utilities%20Proactive%20Planning%20Framework%20Filing.>

methods “often miss granular needs, and underestimate or overestimate the actual need in each area.”¹⁶⁶

- In the September 2025 Order, the New York PSC reiterated the utilities' proposed project eligibility and prioritization criteria:
 - Consideration of whether an upgrade is required to support electrification
 - Consideration of whether construction-related activities would need to begin urgently
 - The degree of certainty of the project
 - Consideration of risks and benefits
 - Alignment with state law and objectives
 - Qualitative and/or quantitative benefits
 - Costs
 - Availability of alternatives
 - Locations or site types
 - Project timelines and financials.
- The Modified Framework put forth by the New York PSC in its September 2025 order includes the following components: study process, data requirements, forecasting methodology, outreach to potential loads, planning assumptions, project proposal requirements, evaluation criteria, procedural approach for project review and potential authorization, cost allocation, and cost recovery.
- In the same Order, the New York PSC directed the Joint Utilities to develop a Proactive Planning Framework Methodology Document to be filed within 60 days of the September 2025 order. The main objective of the Methodology Document is to provide consistency between utilities and “uniformity on data, methods, and assumptions wherever possible and [to] provide explanations of deviations when uniformity is not possible.” Consistency is a key goal in the proceeding.
- At a minimum, the New York PSC said that the Proactive Planning Framework Methodology must identify data sources for each of the following:
 - Assessment of fleet and multi-unit dwelling charging needs
 - Characterization of depots, including locations and vehicle types and counts
 - Enroute and opportunity charging needs
 - Estimated electrification rate by vehicle class
 - Charging power assigned to vehicles
 - Other assumptions related to vehicle electrification grid impacts (e.g., vehicle and charger efficiencies, managed charging assumptions and temperature adjustments)
 - Adoption rate of building electrification technologies, including heat pumps used for space and water heating, as well as other appliances and loads

¹⁶⁶ NY PSC. “Order Adopting Modified Proactive Planning Framework.” September 18, 2025. <https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B80185E99-0000-CF1D-A57E-F4A6874B79D5%7D>.

- Weather-dependent energy and efficiency ratings of BE
 - Estimated deployment of DERs
 - Characterization of economic development load and expansions of existing commercial and industrial load
 - Load forecasts used for benchmarking granular load assessments, and developing overall load estimates.
- The New York PSC also directed the Joint Utilities, as part of the same methodology, to develop forecasts of load out to “at least 2035, with detail provided out to 2040 if possible, acknowledging that uncertainty increases exponentially over time.”
 - Utilities are directed to work directly with building and housing developers, fleet and depot operators, and engage with other relevant stakeholders.
 - Utilities should incorporate granular forecasts into other proceedings, including CGPP cycles, sales forecasts, gas planning work, and future rate cases.
 - Utilities must account for existing and forecasted DERs in forecasts.
 - The Joint Utilities shall follow the tracking methodology within the CGPP, which requires utilities to identify the upgrades that may be sited in disadvantaged communities and evaluate opportunities for directing benefits to and reducing burdens on those locations.

“The utilities shall also collect additional metrics related to building and transportation electrification, economic development, vehicle charging availability, and DER deployment occurring within Disadvantaged Communities, and file them in the Proactive Planning Study Report. These shall include the quantity, in MW, and type of electrification, total charger counts and power ratings, and the quantity, in MW, of DER deployed within Disadvantaged Communities.”

- The Joint Utilities filed a Proactive Planning Framework Methodology in Nov 2025. The Joint Utilities said they “must focus on smaller geographic areas to understand” where granular location-specific loads will appear, such as those caused by electrification and DERs. Existing forecasting does not account for such granular, location-specific data. The utilities do not expect to perform this perfectly straight away with this methodology, but they expect granular load assessment approaches and supporting data will “increasingly inform and integrate into existing forecasts performed at the asset level (e.g., feeder, network, or substation).”¹⁶⁷ They depict how granular data will augment existing forecasting methods to identify grid needs and inform proactive solution design. See Figure 9.

¹⁶⁷ NY PSC. “The Joint Utilities’ Proactive Planning Framework Methodology Document.” Accessed July 2, 2026. <https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={5050989A-0000-C111-99D7-93D1166162F9}&DocTitle=Revised%20Proactive%20Planning%20Framework%20Methodology%20Document>.

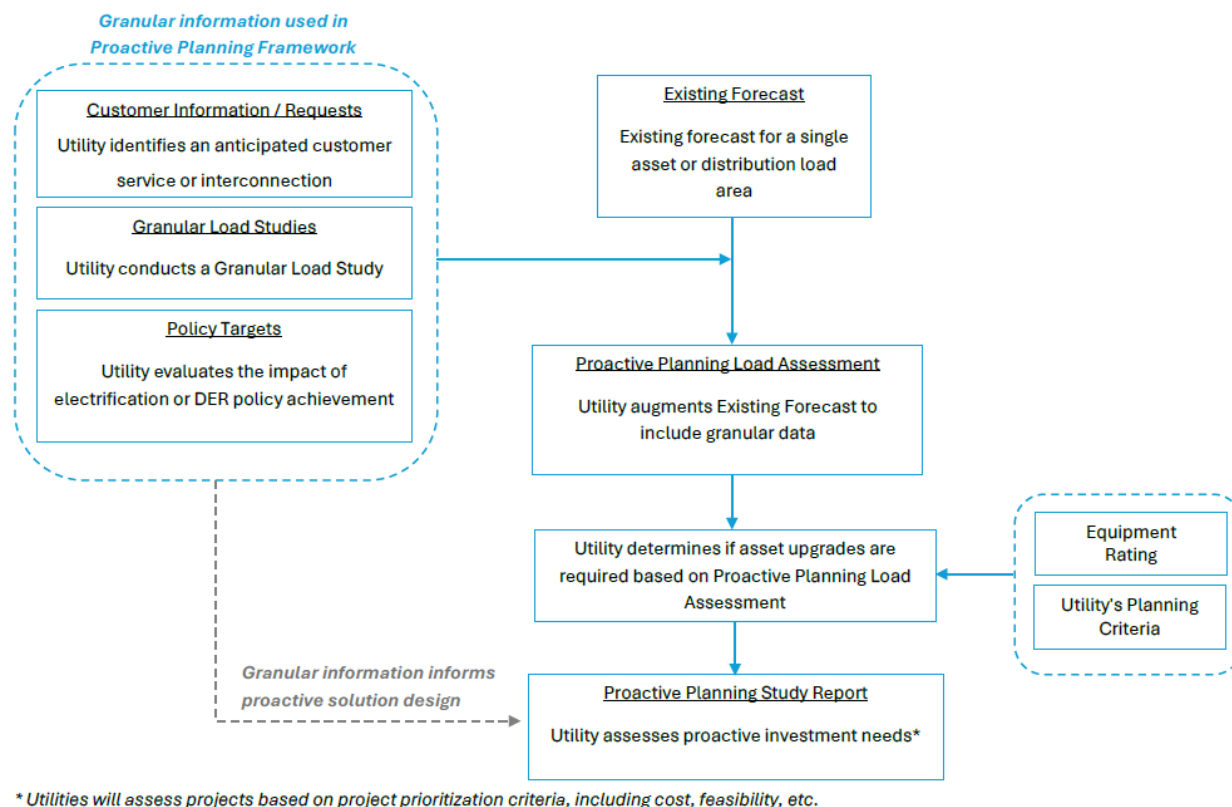


Figure 9. Joint Utilities' Proactive Planning. Flowchart depicting how granular data augments existing forecasting methods to identify grid needs and inform proactive solution design under the Proactive Planning Framework¹⁶⁸

- In their November 2025 filing, for each requirement outlined in the September 2025 Modified Framework Order, the Joint Utilities identified common assumptions and methodologies, common potential data sources, and examples of utility-specific assumptions, methodologies, and data sources. The Joint Utilities also held a follow-up technical conference with stakeholders to present on the methodology and data inputs contained in the Proactive Planning Framework Methodology Document.¹⁶⁹

The final product of the efforts in this proceeding ([Case 24-E-0364](#)) is the filing of a Proactive Planning Study Report to be compiled by the Joint Utilities.¹⁷⁰ Requirements for that study report are listed below (from September 2025 order).

- Joint Utilities must compile a Proactive Planning Study Report identifying grid needs driven by electrification for which proactive investment would improve overall cost-effectiveness, minimize ratepayer impacts, and support policy outcomes. The report will then include the set of project proposals that the utilities deem to meet the evaluation and prioritization criteria, considering input from stakeholders and consultation with New York DPS staff.

¹⁶⁸ Ibid.

¹⁶⁹ Ibid.

¹⁷⁰ NY PSC. "Order Adopting Modified Proactive Planning Framework." September 18, 2025. <https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={80185E99-0000-CF1D-A57E-F4A6874B79D5}&DocTitle=Order%20Adopting%20Modified%20Proactive%20Planning%20Framework>.

- Each project proposal submitted for review by New York DPS staff shall follow a white paper approach containing components such as those requested for the filing of Urgent Upgrade projects. The following information shall be filed:
 - Project Description, including location, key drivers of need, necessary physical components, including total anticipated load increase (in megawatts) and highest anticipated system component voltage (kilovolt), type of project (transmission, sub-transmission, or distribution), presence in a Disadvantaged Community, and Scope of Work.
 - Project Justification, including Project Duration, including dates for the estimated start of construction, estimated end of construction, and estimated in-service date, load components driving necessity as well as current load, spending rationale, customer benefits, alternatives, if any, risks, including that of over- and under-building, and assessment of the potential opportunity for any DERs or other grid-enhancing technologies.
 - Cost, including total spend, broken down by yearly estimates and by capital expenditure and operational expenditure, and proposal for project cost allocation and cost recovery.
- Utilities must file the Proactive Planning Study Report within 1 year of the issuance of the September 2025 Order, or earlier if possible.
- The Joint Utilities are directed to host a technical conference within 30 days of filing the Proactive Planning Study Report enhancing stakeholder review of the proposed projects.
- In addition to the requirements stated previously, utilities must also provide investment grade analysis consistent with the requirements of the Urgent Upgrade Filings, including at a minimum:¹⁷¹
 - Documentation of all feeders, peak summer load, their normal rating, and how many are expected to surpass the normal rating; specific dates for both the needs assessment and proposed project development and construction schedule, including procurement schedules for project components; utility customer electrification plans and existing load requests; historical unit costs for components of proposed projects; data to distinguish between existing load, combined load and electrification loads; capacity headroom projections for 2030, 2035, and 2040; forecasted load growth for 2030, 2035, and 2040; an explanation of the necessity for inclusion in the proactive planning process versus a regular rate case process; and revenue requirements.
- For proactive projects, the Commission will consider cost allocation and cost recovery on a project-by-project basis based on the factors pertaining to each project including, but not limited to, the project-level details, expected beneficiaries, existing capital budgets, relevant provisions within the utility's current rate plan, and the timing of future rate filings.
- The Commission finds that, with the exception of the specific urgency definition and date, the evaluation criteria identified in the Urgent Upgrades Order shall apply and therefore be included in the ultimate filing for each project proposal. For the projects proposed under the Modified Proactive Planning Framework, the urgency criteria shall be based on the specific circumstances of the project and the utility whose territory the project is within. To be eligible for authorization through this generic proceeding, the project must be urgent

¹⁷¹ NY Department of Public Service. "Matter 24-01242/24-E-0364: Case Number 24-E-0364." Accessed July 2, 2026.
<https://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterSeq=73733>.

enough to require early investment that would otherwise not be available under current rate proceeding schedules and shall demonstrate that the early investment makes a meaningful difference related to waiting for authorization in other forums.

- Any projects authorized as proactive upgrade projects must follow the same reporting requirements as those applied to the urgent upgrade projects. Utilities must file status reports every quarter.
- The New York PSC anticipates that the Proactive Planning Framework will drive meaningful improvements in load forecasting. Under the Modified Proactive Planning Framework, New York utilities are expected to collaborate with New York DPS staff to incorporate new analytical tools and modeling approaches into existing planning processes, including the CGPP, distribution load planning, sales forecasting, and future rate cases, where appropriate. Looking ahead, the Commission envisions these currently separate planning efforts converging into a single, standardized process that operates consistently across all utilities and is ultimately administered through the rate case process. The timeline for that consolidation will depend on how much progress utilities demonstrate through successive planning cycles.

8.3.4 Summary of Issues or Concerns Raised

- The Commission, in its August 2024 press release, acknowledged that the “development of integrated planning processes, along with the studies and regulatory approvals, will take a significant amount of time.”¹⁷²
- In the Joint Utilities Proactive Planning Framework (Dec 2024), New York utilities emphasized that a proactive planning process “must effectively coordinate with other regulatory proceedings in a way that either enhances or does not interfere with those processes, without adversely impacting the objectives of proactive planning.” They noted that utilities “do not all conduct ... planning studies on the same timeline and may not use the same assumptions, input data, or methods, thereby making it difficult to compare and evaluate appropriate utility investments statewide.” To effectively coordinate, New York utilities said that there must be a focus on “specific objectives while remaining closely coordinated, primarily through the *alignment* of assumptions, inputs, and outputs at critical milestones” (emphasis added).¹⁷³
- Some points of contention on the proactive planning framework, as summarized in the Commission’s September 2025 Order include:¹⁷⁴
 - Need for consistency in methodology, resources, and terminology across the Utilities, resulting and a standardized framework across the Joint Utilities.

¹⁷² NY PSC. “Commission Announces New Proactive Grid Planning Proceeding to Prepare New York’s Electric Grid for Building and Vehicle Electrification.” August 15, 2024. <https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={80B45791-0000-CF1C-9E64-1BAE60F1B35C}&DocTitle=PRESS%20RELEASE%20-%20Commission%20Announces%20New%20Proactive%20Grid%20Planning%20Proceeding%20to%20Prepare%20New%20York%20C2%BFs%20Electric%20Grid%20for%20Building%20and%20Vehicle%20Electrification>.

¹⁷³ NY PSC. “Joint Utilities’ Long-Term Proactive Planning Framework.” Accessed July 2, 2026. <https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={60C3C193-0000-C42C-9162-2B10D1624579}&DocTitle=Joint%20Utilities%20Proactive%20Planning%20Framework%20Filing>.

¹⁷⁴ NY PSC. “Order Adopting Modified Proactive Planning Framework.” September 18, 2025. <https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={80185E99-0000-CF1D-A57E-F4A6874B79D5}&DocTitle=Order%20Adopting%20Modified%20Proactive%20Planning%20Framework>.

- Emphasis that bottom-up forecasting should be required. Bottom-up forecasting would provide a necessary and more comprehensive granularity to supplement top-down assessments and enable more in-depth analysis.
- Load assessments should be location-specific, granular, and involve forecasts specific to each utility's service territory.
- Load assessments should use multiple sources of data, including non-traditional sources.
- There should be a comprehensive list of cost-effective alternative technologies for utilities to consider, inclusive of non-wires alternatives.
- Load assessment should involve at least three scenarios. Probabilistic forecasting should involve routine scenario analysis that considers a range of outcomes by time and location.
- Some parties thought that there was limited need for the expedited review and approval of projects through the Proactive Planning Proceeding when they can be evaluated in regular rate cases. The parties also expressed that the Proactive Planning Proceeding may risk project-specific approvals or create administrative burden, therefore ordinary rate cases should be prioritized to ensure that there is limited approval of projects outside of them.
- Utility project proposals should provide specific cost allocation details to ensure reasonable approvals and minimize cost impacts on ratepayers. Utilities should be required to conduct thorough assessments of cost-effective alternatives to submitted proposals and demonstrate how projects fit into their investment strategies, including offset or avoided costs.
- Evaluation criteria should consider the role of load flexibility in informing system needs. This should include modeled load forecasts for expected hot spot verification.
- There should be an expansion of the framework section on stakeholder and community engagement. There should be an annual stakeholder technical conferences and broadened stakeholder participation should be encouraged wherever possible, including collaborating with municipalities and fleets for non-traditional sources of data.
- Best practices from the utilities and other commissions should be shared, and the principle of "dig once" should be upheld by the Joint Utilities as best as possible.
- More modest changes to the joint utilities' existing forecasting and planning methodologies would be more appropriate than an entirely new process, particularly because there are overlapping projects between this proceeding and those in rate cases.

9.0 European Anticipatory Investment Approach

9.1 Background

- In June 2025, the European Commission shared a guidance document on anticipatory investments for developing forward-looking electricity networks. The guidance document helps EU countries “create the right conditions so that grid investments reflect future needs, while also ensuring affordability for consumers and the competitiveness of the industry.”¹⁷⁵
- This guidance builds on the EU Action Plan for Grids (November 2023)¹⁷⁶ and the EU Affordable Energy Action Plan (February 2025).¹⁷⁷
- In March 2026, the European Commission, in cooperation with the EU Agency for the Cooperation of Energy Regulators, organized a stakeholder workshop to advance the implementation of the guidance with a focus on “how to mitigate risks related to anticipatory investments through robust network planning and early stakeholder involvement.”¹⁷⁸ The workshop represents a first step in the implementation of the guidance on anticipatory investments.

9.2 Proactive Definitions, Frameworks, or Rationales

- Anticipatory investments are “investments into grid infrastructure assets that proactively address network development needs beyond the ones corresponding to reinforcements relating to currently existing grid connection requests by generation or demand projects. Anticipatory investments are forward-looking network investments based on identified medium- and long-term network needs, justified in network development plans, based on scenarios that project plausible trajectories of generation and demand capacities that support energy and industrial policies.”¹⁷⁹ They should also support achieving EU energy goals.”
- Examples of anticipatory investments include “grid reinforcements, cost-limited preparatory works for enlarging substations or adding spare cable tubes in view of future capacity increases,” and “further facilitate the roll-out of renewable acceleration areas or offshore development areas.”¹⁸⁰

¹⁷⁵ European Commission. “EU guidance on ensuring electricity grids are fit for the future.” June 2, 2025. https://energy.ec.europa.eu/news/eu-guidance-ensuring-electricity-grids-are-fit-future-2025-06-02_en.

¹⁷⁶ European Commission. “EU Action Plan for Grids.” November 2023. https://ec.europa.eu/commission/presscorner/api/files/attachment/876888/Factsheet_EU%20Action%20Plan%20for%20Grids.pdf.

¹⁷⁷ European Commission. “Affordable energy.” Accessed July 2, 2026. https://energy.ec.europa.eu/strategy/affordable-energy_en#affordable-energy-action-plan.

¹⁷⁸ European Commission. “Advancing forward-looking investment in electricity networks.” March 24, 2026. <https://webgate.ec.europa.eu/circabc-ewpp/d/d/workspace/SpacesStore/6a801c0d-dcb9-4c09-8061-fa648478b563/download>.

¹⁷⁹ European Commission. “Commission Notice on a guidance on anticipatory investments for developing forward-looking electricity networks.” June 6, 2025. https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=OJ:C_202503179.

¹⁸⁰ European Commission. “EU guidance on ensuring electricity grids are fit for the future.” June 2, 2025. https://energy.ec.europa.eu/news/eu-guidance-ensuring-electricity-grids-are-fit-future-2025-06-02_en.

- Anticipatory investments should take account of energy strategies, and planning periods should be “sufficiently long” with stakeholders being included “in the early phases of the process, to duly capture future needs.”¹⁸¹

9.3 New or Modified Methodologies

- The March 2026 workshop with over 90 stakeholders from Member States, regulatory authorities, transmission and distribution system operators, generation, consumption, digitalization and data and transport sectors found that there were significant differences across Member States in the “capacity and legal competencies of national regulatory authorities to assess and scrutinize such [anticipatory] investments.” Additionally, anticipatory investments “remains largely a policy concept rather than a clearly defined asset category in practice.”¹⁸²
 - To potentially “significantly alleviate the risk related to anticipatory investment,” multiple scenarios or sensitivities to assess project viability are recommended, in addition to “continuous reassessment of the project until it reaches sufficient maturity (i.e., a staged approach to final investment approval, conducting feasibility studies, environmental assessments and design preparation in one phase, and moving to final investment decision and consequent physical development only if there remains a clear business case for the infrastructure).”
 - To achieve this, sufficient resources of grid operators and regulatory authorities are needed, including for regulatory authorities to “check the assumptions used in detail and to effectively exercise their role in requesting amendments to network development plans.”
 - Stakeholders emphasized the need for “prioritization among grid investments, especially due to scarce workforce, including engineering capacities, and supply chain constraints,” as well as risk mitigation, and concrete models of prioritization.
 - To mitigate risks related to anticipatory investments, “working groups directly feeding into scenario modelling or provision of early information on future estimates of generation or consumption capacity were mentioned among the good practices.” Another good practice was the setup of “regional steering committees with direct participation of mayors, local communities and citizens, which feed into network planning. Participants stressed that public engagement must be meaningful, proportionate and targeted.”
 - Generally, there was agreement that continued dialogue is needed.
 - The March 2026 workshop slide deck highlighted main recommendations from the guidance on anticipatory investments (see Figure 10).¹⁸³

¹⁸¹ Ibid.

¹⁸² European Commission. “Advancing forward-looking investment in electricity networks.” March 24, 2026. <https://webgate.ec.europa.eu/circabc-ewpp/d/d/workspace/SpacesStore/6a801c0d-dcb9-4c09-8061-fa648478b563/download>.

¹⁸³ European Commission. “Workshop on anticipatory investments.” March 11, 2026. <https://webgate.ec.europa.eu/circabc-ewpp/d/d/workspace/SpacesStore/4dbfe929-ae1d-449f-b794-35625420715e/download>.

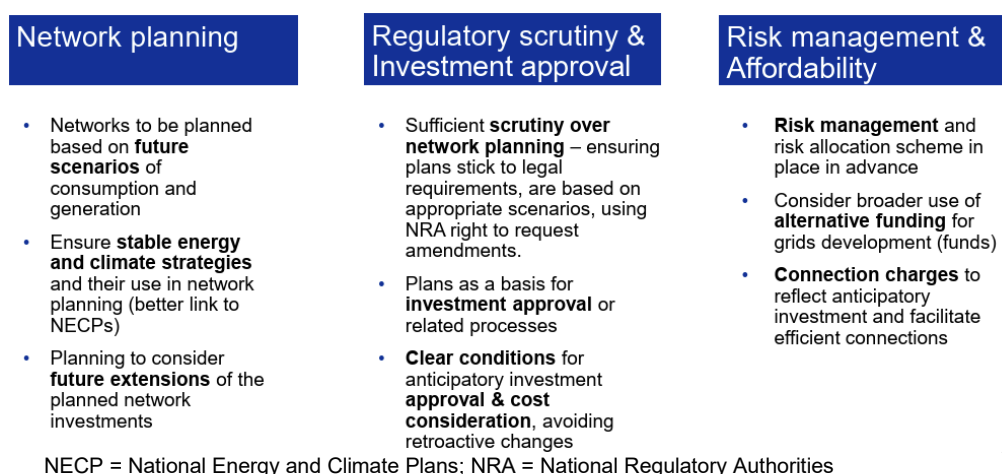


Figure 10. Main Recommendations of European Commission Guidance on Anticipatory Investments for Developing Forward-looking Electricity Networks¹⁸⁴

- The slide deck also highlighted that “regulatory scrutiny should occur mainly ex ante in planning, while providing predictability for approved investments.”
- The slide deck acknowledged that some anticipatory investments are already taking place, but they are occurring “unevenly” across the EU. For example, in Italy and Portugal, substations are designed with room for future expansion. In Germany, low-voltage planning considers long-term connection expectations.
- For anticipatory investments, “clear allocation of risk related to future utilization of the asset should be set up well in advance. In addition, a two-step approval process for accelerating grid projects while minimizing risk and costs could be considered, which cover 1) design and permitting and 2) construction. Once assets are approved, their remuneration should not be retroactively questioned, for instance, if the initial utilization rate of the given asset [is] lower than foreseen.”¹⁸⁵
- Planning of grids “should be based on robust scenarios nurtured by the information collection on planned projects, and a clear national regulatory framework must anchor risk-assessment schemes that allow such [anticipatory] investment to materialize.” Project-related information (e.g., renewable energy, recharging points, heat pumps, storage, etc.) “may provide locational information necessary to further specify concrete grid reinforcement.” Additionally, “local level planning ... can for instance provide information on how heating and cooling demand and supply will evolve locally, creating grid development needs but also opportunities for flexible grid operation and thermal storage.”¹⁸⁶
- In practice, some Member States have “regulatory frameworks [that] generally do not distinguish “anticipatory” investments from other network investments at transmission system operator or distribution system operator level in terms of cost recognition or incentives.”¹⁸⁷

¹⁸⁴ Ibid.

¹⁸⁵ European Commission. “EU guidance on ensuring electricity grids are fit for the future.” June 2, 2025. https://energy.ec.europa.eu/news/eu-guidance-ensuring-electricity-grids-are-fit-future-2025-06-02_en.

¹⁸⁶ European Commission. “Commission Notice: Guidance on efficient and timely grid connections.” December 19, 2025. https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=OJ:C_202506703.

¹⁸⁷ European Commission. “Workshop on anticipatory investments.” March 11, 2026. <https://webgate.ec.europa.eu/circabc-ewpp/d/d/workspace/SpacesStore/4dbfe929-ae1d-449f-b794-35625420715e/download>.

9.4 Summary of Issues or Concerns Raised

- Both transmission and distribution systems across EU countries need upgrades by 2040.¹⁸⁸ It is estimated that “40 to 55% of low-voltage lines [in the EU] will exceed 40 years of age by 2030, while their total length increased only by 0.8% between 2021 and 2022.” Additionally, the growing expansion of new energy sources means that “lengthy timeframes traditionally required to develop grid projects lead to significant delays in connecting to the grid,” with some wind farms facing grid access delays for as long as 9 years.¹⁸⁹
- There are several other challenges:
 1. The “lack of appropriate coordination processes in scenario-building increases the risk of network bottlenecks and delays”
 2. Best practices need to be adopted by EU member states to ensure proper regulatory scrutiny of network development plans to facilitate the inclusion of anticipatory investments
 3. Changes need to be made to network tariff setting, network connection charges and regulatory scrutiny and incentives
 4. There is a need to avoid stranded assets to avoid consumers paying for investments that bring them no benefits.¹⁹⁰

¹⁸⁸ European Commission. “EU guidance on ensuring electricity grids are fit for the future.” June 2, 2025. https://energy.ec.europa.eu/news/eu-guidance-ensuring-electricity-grids-are-fit-future-2025-06-02_en.

¹⁸⁹ Ibid.

¹⁹⁰ European Commission. “Commission Notice on a guidance on anticipatory investments for developing forward-looking electricity networks.” June 6, 2025. https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=OJ:C_202503179.

10.0 Conclusions

The examples compiled in this landscape assessment suggest that some jurisdictions are exploring ways to evolve their planning and investment approaches in response to emerging needs and policy considerations. While the drivers, terminology, and regulatory structures vary, several states are testing or considering methods intended to provide more visibility into future system needs and to better align planning practices with anticipated changes in load, technology adoption, and state goals. In many cases, these efforts remain iterative and exploratory, with commissions, utilities, and stakeholders continuing to refine definitions, methodologies, cost-recovery approaches, and performance expectations over time.

Internationally, the EU's recent guidance on anticipatory investments provides another example of how policymakers and regulators are examining forward-looking grid development, including questions around scenario design, risk mitigation, regulatory clarity, and stakeholder engagement. These developments do not reflect a single settled model, but they offer additional reference points for jurisdictions considering how to incorporate long-term needs and uncertainties into planning and investment processes.

Across the materials reviewed, several themes emerge as areas of continued discussion:

- The potential value of more granular and locally informed load forecasting; the role of scenario planning in managing uncertainty
- The balance between timely infrastructure deployment and ratepayer protections
- The interaction between new approaches and existing planning or rate case structures
- The importance of transparency and stakeholder participation.

The specific solutions that jurisdictions adopt—whether related to cost allocation, performance metrics, hosting capacity, or planning horizons—remain context-dependent and are still developing.

Overall, the landscape points to a period of experimentation and learning, both in the United States and abroad, as utilities, regulators, policymakers, and stakeholders consider different ways to prepare the electric system for evolving demands. This report is intended to document those activities and provide a resource for understanding the range of approaches currently under discussion.

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