

PROACTIVE INVESTMENT FRAMEWORK

TECHNICAL AND REGULATORY CONSIDERATIONS

DECEMBER 2025

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DISCLAIMER

The views contained in this document do not represent the views of any of the CHARGED Working Group Participants' organizations and cannot be attributed to any single Participant.

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PREFACE

OVERVIEW OF THE CHARGED INITIATIVE

The CHARGED initiative supports states as they electrify their transportation and building sectors, ensuring that the electricity distribution system is ready for this new era, while strengthening affordability and reliability for customers. CHARGED engages multiple stakeholders to develop technical solutions that support utility planning and operations for electrification. While CHARGED does not aim to identify a single “standard,” it aims to help the industry move beyond the current state-by-state piecemeal approach to utility planning and operations for electrification. The underlying principle is that processes that bring utilities, technology providers, and public interest groups together in collaborative ways can generate creative and effective solutions that will help utilities and states across the country to learn from each other and accelerate the adoption of effective practices.

CHARGED was launched by GridLab, RMI and Advanced Energy United with a convening in 2024 (“Inaugural Convening”) that brought 60 representatives from a diverse set of organizations together to develop solutions using collaborative problem solving across several technical and regulatory themes. Since the Inaugural Convening, CHARGED has initiated three broad sets of workstreams that traverse solution development to implementation—“ideation”, “implementation”, and “education”:

- ▶ Ideation engages multiple stakeholders across the industry through a collaborative approach to develop innovative solutions with broad applicability;
- ▶ Implementation works with specific organizations at the state level such as utilities to deploy solutions through pro-bono subject matter expertise and facilitation support;
- ▶ Education builds on ideation and implementation to socialize learnings across a wider set of actors, including regulators.

Under the ideation workstream, CHARGED initiated three working groups that directly follow from recommendations developed in the Inaugural Convening—proactive investment framework, flexible grid connection, and GIS best practices. This report contains the final finding and recommendations from an ideation working group that addressed the topic of proactive investment

CHARGED AND PROACTIVE INVESTMENT

At the 2024 CHARGED Inaugural Convening, stakeholders were organized into groups to analyze distribution system challenges from various perspectives. The distribution planning group identified several solutions that could be readily adopted by utilities, which we called “least-regrets” solutions. These included practices such as improved forecasting (with customer engagement) and power flow modeling, proactive upgrades with routine investments, and planning for operational flexibility. The group identified a set of “longer-term solutions” that would require more discussion beyond the capacity of the Inaugural convening and could be taken up as follow-on projects—developing a framework for proactive investment was one such project. A key motivation for this project was that utilities lacked (at the time) proactive investment frameworks. A working group was formed to tackle this subject.



EXECUTIVE SUMMARY

The Proactive Investment Framework described in this report is designed to support interested parties in understanding what proactive investments are, what these investments aim to address and the risks they present, and how processes can be developed and implemented to support proactive investment. This framework discusses how to identify proactive investment opportunities, evaluate prudence of the investments, and design approaches for fairly allocating and recovering associated costs.

Defining proactive investments. Proactive investments aim to provide capacity further ahead of time to enable future growth and are largely driven by forecasts over longer time horizons. This is in contrast to current practices for distribution capacity investments, which are typically driven by relatively certain load growth projections, such as from short-term aggregate customer growth expectations or specific known large load additions.

Risks to consider. The risk profile of proactive investments are different from investments that are made under current practices. For example, proactive investments can have affordability impacts from stranded or underutilized investments. Proactive investments can face inappropriate cost allocation, disallowance or recovery delay, or spur additional challenges from insufficient alignment within the utility. However, investments made under current practices are not without risk, including delayed energization, revenue loss or delay, missed policy objectives, urgency-driven suboptimal investments, inefficient investment, construction logistics challenges, and degraded reliability. Given the different risks presented by both approaches, it is essential to select the right investment approach and to have the necessary mitigation measures in place.

Implementing proactive investments to minimize risks of over investment. Utilities should consider proactive investments only in locations where they provide specific benefits compared to current investment processes. These benefits may include long-run cost-effectiveness, faster connections for new loads, customer experience improvements, or support for state energy goals. Even when considering proactive investments, waiting as long as is practical before starting construction can help reduce risk. Regulators may want to consider having a set of prerequisite processes and capabilities in place before considering proactive investments — such as a regular, transparent and well-structured distribution system planning process; robust forecasting practices that account for and quantify uncertainty, and regular reporting of longer-term forecasting error; more extensive screens for load flexibility and non-wires alternatives; communication of where headroom exists on the system to connect new loads at low cost; rates and harmonized programs that incentivize load flexibility; and data sharing platforms.

Regulatory processes and cost allocation. Proactive investment can include a broad set of approaches, but should only be developed within an advanced regulatory framework where performance is closely monitored. Regulators should ensure that checks and balances are in-place prior to establishing a proactive investment option. While changes to existing ratemaking processes may not be required in many cases, it is essential that there is a strong regulatory process in place if the utility is requesting specific ratemaking treatment, like extraordinary cost recovery, as this can shift risk from utility shareholders to ratepayers. In many cases, traditional cost allocation is based on the cost causation principle, which can also be applied to proactive investments. In some instances it may be helpful to consider future beneficiaries and create spatial cost allocations that reflect investment for certain customer types or areas on the distribution system. However, this too can present new challenges, as alternative cost allocation approaches can add significant complexity.

Protections for ratepayers is crucial when considering proactive investments. Moving forward, it is essential that criteria are developed to assess when proactive investments are appropriate and that there are corresponding metrics to ensure utility performance. Additionally, establishing that utilities have prerequisite regulatory processes in place, such as transparent distribution planning process and proceeding, is critical before implementing a proactive investment framework.

CHAPTER 1.

INTRODUCTION

BACKGROUND AND MOTIVATION

After nearly two decades of essentially stagnant electricity demand across much of the country, the U.S. electricity sector is entering a new period of expected long-term growth. While much attention is focused today on large loads such as data centers, significant load growth is also being driven by transportation, building, and industrial electrification.¹ Electrification is seen as a core strategy for achieving clean energy policy goals, but it is also gaining momentum from technology cost and performance improvements that are leading to increased customer interest in electrified solutions. As utilities make grid investments to accommodate load growth, there is an opportunity to build a cleaner, more flexible, more reliable grid, and to support economic development. Done well, electrification can address affordability challenges being experienced by many electricity customers by spreading utility costs over increased sales.

However, electrification-driven load growth is also creating new challenges for electric distribution utilities and regulators.² There is often a mismatch between the speed at which electrification-related loads materialize and the time it takes utilities to plan, permit, and build supporting distribution infrastructure. For example, while fleet EV chargers can be installed in under a year,³ utility infrastructure upgrades can take several years due to design complexity, supply chain constraints, and the scale of the associated construction activities. Similarly, clustered adoption of EVs and building electrification by residential customers can occur quickly and utilities typically lack visibility into the location and magnitude of the associated load growth.

This creates a conundrum:

Should utilities invest ahead of anticipated load growth to reduce wait times for new or upgraded grid connections but increase the risk of overbuilding if the forecasted growth does not materialize at a given location? Or should they wait for certainty and risk project delays, frustrated customers, unmet policy objectives, and potentially unnecessary expense due to inefficient, incremental upgrades?

To resolve this tension, utilities and regulators should consider adopting new proactive distribution investment planning frameworks that allow utilities to make investments necessary to support anticipated growth and technology adoption while appropriately accounting for and managing associated risks.

1 Transportation electrification includes light-, medium-, and heavy-duty, on- and off-road vehicles, including personal cars, public transit, school buses, maintenance and construction vehicles, and marine, aviation, and rail applications. Building electrification includes space heating, water heating, and cooking appliances. Industrial electrification includes various industrial process heating technologies, as well as industrial heat pumps, electric resistance heating, and thermal batteries (which convert electricity into thermal energy stored for later use).

2 Utilities are also facing significant load growth from data centers. However, there is significant uncertainty about if/when/where new data center load will materialize and how it might impact the distribution system. Therefore, planning for new data center load is not in the scope of this report.

3 Energy Systems Integration Group. 2023. Charging Ahead: Grid Planning for Vehicle Electrification. A Report of the Grid Planning for Vehicle Electrification Task Force (hereinafter "ESIG Vehicle Electrification"), Reston, VA. <https://www.esig.energy/grid-planning-for-vehicle-electrification>.

CURRENT INVESTMENT PRACTICE VS. PROACTIVE INVESTMENT

Under current investment practices, distribution capacity investments are typically made in response to confirmed customer load additions or anticipated load growth with “reactive” infrastructure deployment. Investments using this process can, in actuality, have a degree of “proactive” flavor, as they may be justified based on load growth forecasts in the short term (e.g., the next 1-3 years). Cost recovery for such investments is typically straightforward because the investments are tied to reasonably certain load growth from specific customer load additions or high-confidence short-term aggregate customer growth. In contrast, proactive investments are intended to enable future growth by removing barriers to future growth, with specific future needs generally identified using forecasts with longer time horizons.

Proactive investment practices are generally not intended to replace the current investment practices, but rather to supplement them, acting as a tool to achieve specific goals not well served by the existing process. The proactive approach can achieve unique benefits such as improved customer experience, support for state policy goals, or improved long-run investment efficiency, but also comes with additional uncertainty as a result of the increased reliance on forecasted conditions further into the future. This additional uncertainty increases the risk that proactive investments may occur earlier than they are actually needed (resulting in investment inefficiency), but reduces the risks of delayed customer energization and missed policy goals. Enhancements to distribution capacity planning, approval, and recovery processes are therefore needed in order to achieve the benefits of proactive investments while addressing these challenges and risks.

PURPOSE OF THIS REPORT

This report explores the risks and opportunities associated with proactive investments and develops an options framework for deploying and regulating such investments. It provides an overview of the design choices that regulators and utilities will need to consider in developing forecasting methods, needs assessment tools, solutions strategies, and ratemaking and other regulations for proactive investments.

It is important to recognize that there will be significantly different levels of benefit and urgency for proactive investments across different states and utility territories, depending on the speed of electrification adoption and the amount of capacity currently available within their distribution systems. This report is intended to help utilities, regulators, and other impacted stakeholders understand whether a proactive investment process could be used effectively to meet their specific anticipated needs.

While this report is focused on proactive investment for electrification-driven load growth, many concepts may apply to proactive investments more broadly, including those to support distributed energy resources (DERs). The goal of this report is to provide regulators and utilities with tools to support timely, cost-efficient, fair, and reliable distribution infrastructure deployment in an era of higher load growth.

Because prudence, cost allocation, and cost recovery are such critical aspects of proactive investment, there is significant focus on regulatory constructs and mechanisms used to regulate investor-owned utilities (IOUs). While some aspects of this framework will not be directly applicable to municipal and cooperative utilities, the core concepts and approach can still be utilized by such utilities to identify, justify, and deploy proactive investments.

The report is organized as follows:

- ▶ **Chapter 2: Key Considerations for Framework Design** – describes the risks of action and inaction for proactive investments, how proactive investment changes paradigms for prudency determination and cost allocation, and potential avenues for stakeholder engagement in reviewing proactive investments.
- ▶ **Chapter 3: Identifying and Assessing the Appropriateness of Proactive Investments** – discusses methods for load forecasting, needs identification, and solutions scoping, sizing, and timing associated with proactive investment.
- ▶ **Chapter 4: Regulatory Approval, Cost Recovery, and Risk Management** – outlines potential options for allowing utilities to recover the costs and manage the risks of proactive investments.
- ▶ **Chapter 5: Cost Allocation** – explores options for allocating the costs of proactive investments across customers.
- ▶ **Chapter 6: Conclusion** – synthesizes the high level insights of the report.

CHAPTER 2.

KEY CONSIDERATIONS FOR FRAMEWORK DESIGN

While proactive investments involve forecast-based uncertainty, they can also provide additional benefits where:

- ▶ There is potential for load growth in an area to occur faster than distribution infrastructure can be built,
- ▶ There are potential logistical challenges (i.e., system switching limitations or equipment availability) from constructing too many upgrades in a given year,
- ▶ Overall life-cycle costs can be reduced by incorporating longer-term capacity needs and avoiding inefficiencies from repeated projects at the same location (i.e., opportunity to leverage economies of scale).

Distribution planners and regulators must weigh the risks of investing proactively against the risks of waiting. At the same time, regulators must determine whether these investments are prudent and ensure that the associated costs, benefits, and risks are shared fairly. Pursuing proactive investments may also require the integration of such investments with existing regulatory processes (e.g., rate cases, distribution system planning proceedings, and beneficial electrification proceedings) without duplicating efforts or adding unnecessary complexity and burden on regulators and stakeholders. Meaningful stakeholder engagement is essential throughout this process, particularly for improving load forecasts and identifying where and when investments are needed. Effective stakeholder engagement can help identify and integrate these solutions into utility planning and operations. There is also a growing set of DER solutions that can increase demand flexibility and help address load growth within a proactive investment framework.

This chapter:

- ▶ discusses investment risk factors for both proactive investments and current investment practices;
- ▶ considers how proactive investments' reliance on longer-term, more uncertain forecasts results in challenges to the prudence determination approach used for current investments;
- ▶ analyzes who is impacted by the costs and benefits of proactive investments, and what happens if load does not materialize as expected; and
- ▶ discusses the importance of stakeholder engagement, and how feedback should be incorporated into distribution system planning proceedings.

INVESTMENT RISK FACTORS BY APPROACH

Risks associated with proactive investments may include the following:

- ▶ **Affordability impacts from stranded or underutilized investments** – the risk that an investment does not fully achieve its intended value because actual load growth at the impacted location is materially lower than the forecasted load growth when the investment was made, and the potential for increased customer costs because of underutilization

- ▶ **Unsuitable investments** – the risk that the deployed assets are not the best option to serve load growth as it occurs, for example, in a situation where investments in DER integration capabilities would lower costs overall or mitigate risk more effectively than simply investing in traditional grid capacity
- ▶ **Inappropriate cost allocation** – the risk of inequitable recovery of costs across ratepayers, since cost allocation is established before it is clear who the actual cost causers and beneficiaries are⁴
- ▶ **Disallowance or recovery delay** – the risk that regulators determine that an investment is not prudent and disallow or delay recovery of all or part of its costs
- ▶ **Poor utility internal alignment** – due to disparate decision-making frameworks (e.g., separate reactive and proactive mechanisms) and responsibilities for grid investments within a utility, there is a risk that investments will not be located, coordinated, or sequenced in such a way as to minimize overall costs to ratepayers or efficiently integrate loads⁵

Risks of current investment practices include the following:

- ▶ **Delayed energization** – the risk of negatively impacting customers’ experiences and their ability to adopt new technologies (e.g., dampening or slowing EV adoption)
- ▶ **Revenue loss or delay** – the risk that customers may not benefit from the potential downward pressure on rates from the new revenue associated with increased system throughput
- ▶ **Missed policy objectives** – the risk of hindering local, state, or federal policy requirements
- ▶ **Urgency-driven suboptimal investments** – the risk of selecting investments under time pressure, which may limit the ability to plan adequately and select lower-cost alternatives⁶
- ▶ **Inefficient investment** – the risk of having to revisit assets or locations multiple times due to limited foresight
- ▶ **Construction logistics challenges** – construction of a large number of upgrades in a given year may stress construction logistics and the availability of switching, increasing labor costs and delaying construction completion
- ▶ **Degraded reliability** – the risk that sudden increases in load overwhelm constrained infrastructure and prematurely degrade equipment

With these risk factors in mind, selecting the right investment approach and ensuring it is supported by the necessary mitigation measures and enabling conditions is essential to achieving prudent, cost-effective, and policy-aligned outcomes. Table 1 below compares these approaches across key risk and benefit dimensions, providing a structured view of the trade-offs that must be weighed when determining how best to meet electrification-driven load growth. We discuss options for analyzing and mitigating these risks in Chapters 3 and 4.

4 Lawrence Berkeley National Laboratory (LBNL). Unlocking Load Growth at the Grid Edge: Practices for Managing, Recovering, and Allocating Distribution System Investments (hereinafter, “LBNL Unlocking Load Growth”). January 2025. p. 50-51. <https://emp.lbl.gov/publications/unlocking-load-growth-grid-edge>

5 PNNL. Proactive Regulatory Approaches to Electrification and Load Growth: Workshop Report. January 2025. p. 3. https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-37135.pdf

6 LBNL Unlocking Load Growth, p. 49-50.

TABLE 1. Comparison of risk factors between reactive and proactive investment approaches⁷

■ Low
 ■ Medium
 ■ High

RISK FACTOR	CURRENT INVESTMENT APPROACHES	PROACTIVE INVESTMENT APPROACHES
Lifecycle Cost Impact	■ higher unit costs, recurring work/ revisit assets, and lost synergies between investments	■ minimizes potential repeated work and prevents urgency-based inefficiencies
Stranded/ Underutilized Asset Risk	■ investments made after growth is known	■ risks driven by potential for forecast inaccuracies ■
Utility Cost Recovery Risk	■ investments justified by known load growth	■ depends on Regulatory Process Design
Dissatisfaction of Customers Adopting Electrification Measures	■ delays in new connections likely due to lack of capacity	■ capacity available for new / upgraded connections without delays
Policy Alignment Risk	■ lags policy timelines	■ removes barriers to achieving policy goals
Execution Complexity	■ simpler planning, but requires rapid mobilization under pressure; fewer complex forecasting models ■	■ requires complex forecasting, integrated processes, and robust project justification

PRUDENCY DETERMINATION

Under current investment practices, regulators allow cost recovery through the rate base (or other mechanisms such as riders) if an investment is both “used and useful” in providing service and its cost was prudently incurred. Utilities bear the burden of proof and regulators determine compliance after reviewing evidence and considering input from intervenors.⁸

Proactive investment changes this dynamic, as decisions are based on longer-term and more uncertain forecasts. There is a risk that proactive investment assets will not be fully used if the load does not materialize at the expected time and location, and thus the investment may not be prudent under existing regulatory practices (i.e., the utility cannot demonstrate that, without the assets, either costs would be higher, or the quality of service would be lower).

Even if not fully used and useful, a regulator may still determine that a utility made a proactive investment prudently if it can demonstrate that:

- ▶ it is or was based on a robust forecasting methodology and confidence in the need for the investment is/was high;
- ▶ the risks of NOT making the investment are/were too high, or the consequences of waiting are/were unacceptable;
- ▶ it is/was the best investment alternative given the information the utility has/had at the time; and
- ▶ the proactive investment provided the most cost-effective solution.

⁷ In this context, “Low”, “Medium”, and “High” designations are intended to show the relative risk for each approach when compared to the other, including cases where planned growth materializes and cases where it does not.

⁸ Lazar, J. Electricity Regulation in the US: A Guide. Second Edition (hereinafter, “RAP Electricity Regulation in the US”). Montpelier, VT: The Regulatory Assistance Project. 2016. p. 52. Retrieved from <https://www.raponline.org/knowledge-center/electricity-regulation-in-the-us-a-guide-2/>

A utility should also demonstrate that the proactive investment process is the appropriate vehicle for the investment and that it has thoroughly evaluated all viable alternatives, such as the load-reducing potential from customer-owned DER, energy efficiency and other demand-side management, load flexibility, time-of-use rates, or EV managed charging.

When establishing a proactive investment framework, regulators should establish upfront the criteria they will use for determining prudence and the information they expect to receive from utilities to demonstrate that prudence. This will mitigate the risk of disallowance and reduce utility hesitancy to make proactive investments, and support more robust stakeholder engagement. This is discussed further in Chapter 4.

FAIR DISTRIBUTION OF BENEFITS, COSTS, AND RISK

One of the fundamental challenges with pursuing proactive investments and creating a future-ready grid is fairly allocating costs and risk, which can be explored through a few key questions:

- ▶ Who pays for grid upgrades?
- ▶ Who benefits from those upgrades?
- ▶ What happens if the load does not materialize?⁹

As discussed earlier, utilities typically cannot recover costs for assets that are not deemed “prudent,” making them reluctant to invest without certainty about future load and/or approval for cost recovery. Depending on the asset type and state regulations, the customer driving the new load may be required to pay a portion of any associated grid infrastructure costs. In other cases, the cost of assets are spread across all ratepayers. Each of these approaches shifts risk to a different group and each carries trade-offs.

Equity considerations are also critical. Without thoughtful planning and cost allocation, proactive investments could disproportionately burden low-income customers with rate increases while primarily improving the connection speed for wealthier early adopters or commercial entities. In addition, the beneficiaries of such projects are future connectors, despite being paid for by current customers, creating the potential for inequity. Because of these risks, regulators should revisit how infrastructure costs are allocated and recovered as part of their development of a proactive investment framework. Traditional cost recovery mechanisms may be insufficient.¹⁰

In Chapter 5, we further discuss ways to mitigate and appropriately share risk across parties.

STAKEHOLDER ENGAGEMENT

Traditionally, distribution investment planning has been managed almost exclusively by utility engineers with limited transparency into the data, assumptions, and methods behind their decisions. While stakeholders can review utility investment plans during general rate cases, these proceedings are often contentious, time-consuming, and resource-intensive for both regulators and intervenors.¹¹ These transparency challenges are one reason why many states are adopting formal distribution system planning proceedings that increase stakeholders’ access to information on utility planning processes and future investment needs.¹² While not essential for implementing

⁹ ESIG Vehicle Electrification, pp. 60-61.

¹⁰ Id., pp. 13-14.

¹¹ GridLab. Integrated Distribution Planning: A Path Forward (hereinafter, “GridLab IDP”). April 2019, p. 6. <https://gridlab.org/portfolio-item/integrated-distribution-planning/>

¹² Lawrence Berkeley National Laboratory. State Distribution Planning Requirements. Updated 2025, <https://emp.lbl.gov/state-distribution-planning-requirements>

a proactive investment approach, this type of modern distribution system planning provides an important venue for addressing many of the issues covered in this proposed proactive investment framework.

The table below provides an example from a proceeding in Connecticut with a framework of how electric delivery companies (EDCs) (i.e., utilities) could structure stakeholder engagement throughout an integrated distribution system planning (IDSP) process.

TABLE 2. *Proposed Stakeholder Engagement for the IDSP Process, from State of Connecticut proceeding on Integrated Distribution System Planning*¹³

IDSP IN DEVELOPMENT		IDSP DRAFTED	
MODE OF ENGAGEMENT	DESCRIPTION	MODE OF ENGAGEMENT	DESCRIPTION
Input	Provide opportunities for stakeholders to share information and data with the EDCs on their plans and proposals that may support the IDSP forecasts and grid needs.	Inform	Share IDSP information and data with stakeholders in a suitable and accessible format.
Consult	Share information with stakeholders on preliminary IDSP hypotheses, approaches, and plans, and invite stakeholder dialogue to ensure IDSP development is representative of stakeholder views and activities and meets the needs of customers.	Consult	Share IDSP information and data and invite feedback on the proposals from stakeholders.
Invite Scrutiny	Provide opportunities for stakeholders to assess and review IDSP processes and assumptions, and source feedback to improve these processes and assumptions.	Invite Scrutiny	Provide opportunities for stakeholders to assess and review IDSP conclusions and results, and source feedback on the conclusions and results.

Successful proactive grid investment requires close coordination between utility planners, regulators, developers, and a broad set of stakeholders including communities, customers, equipment and vehicle manufacturers, charging providers, aggregators, and others.¹⁴ These stakeholders can help define planning objectives, establish success metrics, help to identify and characterize the full range of potential solutions, and contribute valuable data on when, where, and how much electrification-driven capacity will be needed.¹⁵ This stakeholder engagement should take place during all steps of the proactive investment lifecycle, including developing the proactive investment planning framework, undertaking the analysis (e.g., via a distribution system plan or dedicated proceeding), and on an ongoing basis as the utility pursues and invests in the portfolio of solutions.

Increased transparency can improve the accuracy of load forecasts and support more equitable outcomes. Stakeholders can review and provide input on the data, methods, and assumptions used

¹³ Docket No. 21-05-15RE03, PURA Investigation into the Establishment of Integrated Distribution System Planning Within a Performance-Based Regulation Framework. [https://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/434c4c1cc98d1dd185258cb2005ee6b4/\\$FILE/21-05-15RE03%20final%20brief.pdf](https://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/434c4c1cc98d1dd185258cb2005ee6b4/$FILE/21-05-15RE03%20final%20brief.pdf)

¹⁴ ESIG Vehicle Electrification, p. 57.

¹⁵ Rocky Mountain Institute. Transportation Electrification Building Blocks - Practical Guidance for Regulators and Utilities to Strategically Plan for Rapid Electric Vehicle Load Growth. October 2024, p. 35. <https://rmi.org/insight/transportation-electrification-building-blocks/>

in forecasting models. Utilities can facilitate this engagement by hosting workshops to explain their approach and gather feedback. Reaching early agreement on key assumptions and methodologies helps build a shared understanding of future electrification and grid needs, while also reducing conflicts later in regulatory proceedings by addressing potential points of contention in advance.¹⁶

Early and ongoing engagement with communities is essential to aligning proactive investments with community plans and needs. This means gathering input on both broad policy decisions and specific utility plans, and keeping communities informed throughout implementation.¹⁷ A broader look at historical inequities in customer outcomes and system investment can also be considered for proactive investments.

Utilities can also use visual tools such as “load hosting capacity” maps to engage stakeholders and highlight where the grid can accommodate new load without major upgrades. These maps help identify areas with available capacity, guiding, for example, fleet operators and charging providers toward locations that can support new demand more quickly and cost-effectively. By reducing the need for extensive coordination, this proactive approach can shorten electrification timelines and streamline the load connection process.¹⁸ Figure 1 illustrates this concept for Ameren Illinois.

We discuss stakeholder engagement further in Chapters 3, 4, and 5.

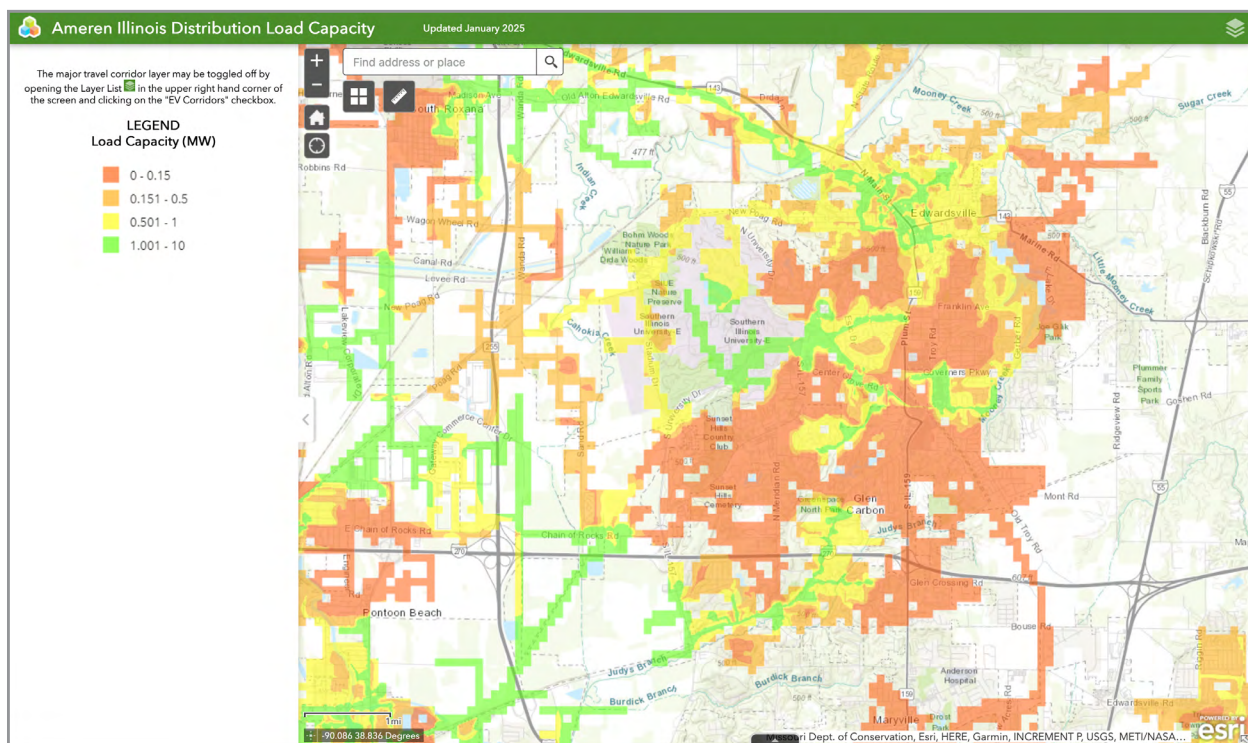


FIGURE 1. EV/Load Capacity Map for Ameren Illinois¹⁹

¹⁶ Id., p. 30.

¹⁷ Environmental Defense Fund. Building the Grid to Need - Best Practices for Proactively Developing Distribution Grids to Support Truck and Bus Electrification (hereinafter, “EDF Truck and Bus Electrification”). January 2024. p. 21. <https://www.edf.org/sites/default/files/2024-01/BuildingGridforNeed2024-01.pdf>

¹⁸ Smart Electric Power Alliance. Preparing for Customer Fleet Electrification: A Utility Framework. October 2023, p. 11. <https://sepapower.org/resource/preparing-for-customer-fleet-electrification-a-utility-framework/>

¹⁹ Ameren, Ameren Illinois Distribution Load Capacity, <https://www.arcgis.com/apps/webappviewer/index.html?id=c1be35bcc1f4ae9a8af5a1e2a69c268>

CHAPTER 3.

IDENTIFYING AND ASSESSING THE APPROPRIATENESS OF PROACTIVE INVESTMENTS

The process for identifying and assessing the appropriateness of proactive investments follows the same general process as traditional distribution planning, but with additional complexity at each stage to estimate, account for, and manage uncertainty. Starting from a forecast, potential system needs are identified and solutions are designed and prioritized alongside other potential utility investments. Ultimately, proactive investments will be scrutinized for their prudence and necessity alongside other utility investments. The figure below illustrates the key steps in proactive investment decision making.



FIGURE 2. Key Steps in Proactive Investment Decision Making

This chapter:

- ▶ discusses forecasting considerations needed for proactive investment and the impact of increasing time horizons to identify and evaluate these investments;
- ▶ considers system capacity needs including how different scenarios can be leveraged for decision-making to identify potential needs, and modifications that are needed within existing planning processes;
- ▶ analyzes factors to consider when selecting the correct solution to address the challenge, and effectively sizing investments to consider potential future load growth; and
- ▶ discusses the need for project evaluation criteria, especially given potential forecast uncertainty.
- ▶ Note, the steps of regulatory approval, cost recovery and risk management; and cost allocation are discussed in chapters 4 and 5.

DISTRIBUTION FORECASTING CAPABILITIES AND ENHANCEMENTS

- ▶ Key questions discussed in this section:
 - How can the load forecast be improved in order to better inform decisions about medium- and long-term needs?
 - What new sources of input data can improve proactive planning and investment outcomes?
 - How can the relative accuracy of and confidence in the forecast be determined and used to inform utility decision-making and commission oversight?

Historically, distribution planning forecasts have been relatively deterministic, applying anticipated percentage growth and known customer load additions over relatively short time horizons and with relatively high confidence. More often than not, these traditional approaches result in a single forecast that does not meaningfully quantify or engage with uncertainty or risk. While these types of forecasts can still be useful for proactive planning efforts, enhancing forecasting methods to better account for a variety of potential futures and to appropriately quantify and manage risk can significantly improve the process of identifying and justifying specific proactive investments.

Increasing the time horizon of distribution planning forecasts is an important enhancement that supports identifying potential grid needs beyond the typical five-year window. This allows for more opportunities for proactive investments to be identified and evaluated. A longer forecast window does not necessarily mean that all investments should be made further in advance of need. Rather, it provides more opportunities to identify and evaluate potential proactive investment opportunities that may not otherwise be identified.

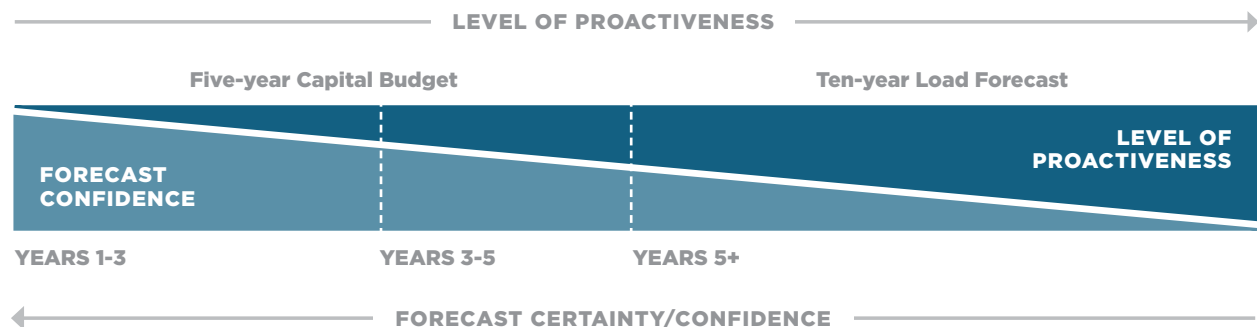


FIGURE 3. *Timeline Considerations (Figure courtesy of Zach Pollock, Xcel Energy)*

Forecasts going out ten years can more readily identify proactive investment opportunities in advance of the need, especially in areas where procuring land and materials and constructing new distribution infrastructure may take several years to complete. Longer-term forecasts beyond the ten year horizon can be utilized to anticipate the overall magnitude of future needs and can be used to inform equipment sizing decisions for proposed investments today in order to ensure that new equipment is sized to support anticipated load growth as needed throughout its entire useful life. Sizing equipment when reactive to incremental load additions may result in the need for additional upgrades down the line, resulting in higher overall lifecycle costs. Longer-term forecasts can help facilitate acquisition of land and easements for new substations or feeder routes, which can help avoid significant delays and can help shrink construction timelines.



Expanding forecasts from a single, deterministic result to consider multiple scenarios or incorporate probabilistic elements can significantly improve the usefulness of forecasts in identifying proactive investment opportunities. Scenarios may be used to consider a variety of specific future conditions such as “low”, “medium”, and “high” adoption cases for one or more specific load types or DER technologies, the achievement of state energy policy goals, the implementation of programs or incentives to accelerate electrification or DER adoption, or other future conditions. Scenario-based approaches can also reveal least-regrets investments with benefits across a number of different future outcomes related to demand growth or technology adoption. Probabilistic approaches can be used to estimate the likelihood of varying levels of adoption and may be used on their own or in the development of specific scenarios within the forecasting process.

In order for these scenario-driven and probabilistic approaches to be useful for the later stages of the planning process, it is necessary to map load growth and technology adoption to specific geographic areas and the corresponding distribution infrastructure. This often involves utilizing “bottom-up” locational data such as land parcel and zoning data, customer adoption propensity modeling, or vehicle telematics data as a means of allocating system-level forecast scenarios to specific locations supported by specific distribution infrastructure.

Modern distribution forecasting tools can provide estimates of the level of confidence that a particular land parcel will be developed or a particular customer or class of customers will adopt specific technologies. These confidence estimates can be useful in understanding the relative risk of making a proactive capacity investment in a given area. Where load growth is driven by higher volumes of smaller load additions (e.g., residential home electrification), the relative confidence in the magnitude of customers adopting the new technology in the area is likely more critical to proactive capacity planning than the probability of any individual customer’s adoption. Where individual new large loads are predicted to drive distribution system growth (e.g., fleet electrification), the level of confidence of the particular location and size of the load addition is much more critical to understanding potential risks for subsequent proactive investments.

As an example, Public Service Company of Colorado (PSCo) has recently evolved its forecasting capabilities to enable more proactive planning, as shown in Figure 4 from PSCo’s recent Distribution System Plan.







	PRIOR TO 2021	2021 TO 2022	2023 TO 2024
 Forecasting Methodology	Reactive & Deterministic	Reactive, Deterministic & Probabilistic	Proactive & Probabilistic
 Temporal Considerations	Peak Hour per Asset & Growth Coincident with Peak	Time-Series TLY Curves (8760) & Load Curves	Time-Series TLY Curves (8760) & Load Curves
 Forecasting Adoption	Applied Fixed Growth Rate	Spatial Allocation & Propensity Modeling	Spatial Allocation & Propensity Modeling
 Growth Vectors	Service Applications	Spatial Allocation & Corporate Energy Sales	Service Applications, Corporate Energy Sales, Clean Heat Plus BE, EV Growth, BTM PV
 Planning Scenarios	Single Scenario	Single Scenario	Two Scenarios
 Forecasting Tools	Itron’s Distribution Asset Analytics (DAA)	Integral Analytics’ LoadSEER	Integral Analytics’ LoadSEE

FIGURE 4. PSCo’s Evolution of Distribution System Forecasting^{20,21}

Forecasts also need to account for changes in utility program and rate offerings, rebates and tax incentives, or flexible service connection options. Utility-managed EV charging programs, for example, may shift the magnitude, duration, and timing of EV charging load. Additional locational incentives through programs such as geo-targeted demand-side management may impact the location and magnitude of load or DER technology adoption and the subsequent impact on distribution system needs. To ensure forecast accuracy, the impact of existing and planned program offerings on the amount of anticipated adoption of a technology and its operating profile should be captured within forecasts for proactive planning purposes.

Increasing utilization of electric heat pumps for space heating can significantly impact system planning considerations (see callout box), especially in areas where natural gas has historically been available and utilized for space heating. Consequently, state or regional plans related to the future of the natural gas distribution system are also important inputs to the forecasting process. In addition, incorporating weather-based scenarios into the planning and forecasting process can help better capture potential impacts on electric load due to extreme heat or cold.

20 Hearing Exhibit 101 - Direct Testimony and Attachments of Jack W. Ihle, PSCo 2025-2029 Distribution System Plan and the Grid Modernization Adjustment Clause, Public Utilities Commission of the State of Colorado, Docket 24A-0547E, December 16, 2024, Figure JWI-D-3, p. 40.

21 Key terms include: Typical Load Year (TLY), Beneficial Electrification (BE), Electric Vehicle (EV), Behind-the-meter Photovoltaic Solar (BTM PV), LoadSEER forecasting software from Integral Analytics

IMPLICATION OF WEATHER ON PROACTIVE PLANNING FOR ELECTRIFICATION

Load impacts from building electrification will increase the seasonality and weather dependence of loads, as well as increase the vulnerability of the power system to extreme weather, largely due to heating demand. In some winter-peaking electrification futures, solar generation is misaligned with the time of highest demand—just before dawn when it's typically coldest. Additionally, building electrification requires the integration of traditionally independent planning processes for energy delivery systems (fossil fuel and electricity), which can change how planners weigh the pillars of reliability, resilience, affordability, and sustainability.

Building electrification can also present hidden risks when planners who have traditionally been oriented around summer peaks miss how building electrification can affect loads in the winter. Given the physics of today's heat pump technology, which may be more energy efficient than air conditioners when they are replacing older cooling technologies, some regions may see load decreases during the summer months. Distribution system planners may not see the significance of building electrification until faced with high demand on the coldest days in winter. A good understanding of these stressors is necessary to effectively plan the grid. (Energy Systems Integration Group. 2024. Grid Planning for Building Electrification. Reston, VA. <https://www.esig.energy/grid-planning-for-building-electrification/>)

Stakeholder engagement can help provide important inputs to the forecasting process and provide important context on the reasonableness of the results. Municipalities, especially those which have developed their own electrification plans, can help ensure that forecasts reflect planned electrification initiatives to identify potential areas of need. State agencies such as departments of transportation can provide input on EV charging deployment timing, size, and location. Customers with fleets can help identify areas of potential expansion and the timing of needs in those areas. On the whole, stakeholder engagement is an important step to refining forecasting inputs and reviewing the results.

While all of these enhancements to the forecasting process are important steps to improving proactive planning and investment capabilities, not all utilities are at the stage where the implementation of such enhancements is practical in the short-term. It may still be beneficial for such utilities to pursue proactive investments if significant growth is anticipated in their territory, but they should be approached with more hesitancy or in a more targeted manner. More traditional 5-year, deterministic forecasts can still serve as a useful input to proactive planning and investment identification, albeit with significantly more limitations. Since such forecasts do not incorporate risk, it is much more difficult to determine the appropriate timing and scale for proactive investment and the potential for asset under-utilization. Consequently, other mechanisms of understanding anticipated needs, such as stakeholder engagement or municipal electrification plans, are more critical to providing sufficient justification to move forward with specific proactive investments. In such cases, it may also be beneficial to take concrete steps towards more sophisticated forecasting to improve the identification and justification of future proactive investments moving forward.

SYSTEM CAPACITY NEEDS IDENTIFICATION

► KEY QUESTIONS DISCUSSED IN THIS SECTION

- How can forecast results be translated into specific system capacity needs that may suggest the need for proactive investments?
 - How can different scenarios be incorporated into decision-making to effectively identify potential needs and priorities?
 - What modifications to the existing planning process may be beneficial when considering proactive investments?
-

Once a suitable forecast has been developed, it can be used to identify potential capacity constraints in future years, including potential proactive investment needs. For transformers and circuit equipment within substations, capacity constraints are generally readily identifiable directly from the forecast. For capacity constraints on line equipment outside the substation fence, power flow analysis may be needed to estimate loading for non-metered components.

When utilizing probabilistic or scenario-based forecasts, capacity needs may occur under some expected futures but not others. Navigating this additional complexity is central to effectively identifying future capacity needs and the resulting proactive investment opportunities. One method used within scenario-based planning is to select a single “likely” case to drive system needs identification. This approach simplifies the process of identifying grid needs, but does not make full use of the available data about the entire range of possible futures. Instead, separately identifying which capacity needs emerge within each scenario can guide decision-making for proactive investments more effectively based on actual risks. For instance, when a system need emerges in most or all forecast scenarios, addressing that need could be considered “least-regrets” compared to a need that only occurs in one scenario.

Investments that expedite future construction are another potential avenue of proactive investment that can help improve construction timelines while minimizing the risk of under-utilized assets. Increasing stock levels for long lead time equipment such as substation transformers or high volume components such as service transformers can help reduce the timeframe between identifying a system need and completing a system upgrade. Because these components are stocked, they can be utilized wherever growth occurs, and are thus not dependent upon a locational forecast and do not come with location-specific risks. In addition, where new substations are anticipated, starting real estate and right-of-way acquisition early can ensure the availability of suitable land and pathways for necessary line extensions. Both equipment stocking and real estate acquisition can be tied to anticipated system growth to adjust current practices to anticipated needs using proactive investment techniques.



Updating planning processes to support proactive investment identification can be a great time to re-examine existing planning criteria in order to maximize available capacity and ensure existing resources are being fully utilized. For example, when considering DERs such as solar photovoltaic (PV)s, many utilities do not take into account the load-reducing effects of local generation or demand reduction on peak loads and capacity needs. Techniques such as PV Dependability Analysis can be used to incorporate these load-reducing effects, enabling additional capacity at minimal cost. Rather than assuming that PV contributions are entirely unreliable, PV Dependability Analysis uses statistical methods to estimate the degree of PV production that is reasonable to expect during different time periods or seasons (see Figure 5). This allows a non-zero portion of PV production to be reliably counted as a capacity resource. Southern California Edison’s Dependable Photovoltaic Generation Methodology is one such example, and the Dependable PV profiles used for each season in two different regions are exemplified below.²² Additionally, incorporating customers with flexible or interruptible loads, especially when considering contingency scenarios, can help to further maximize the use of existing infrastructure for capacity planning.

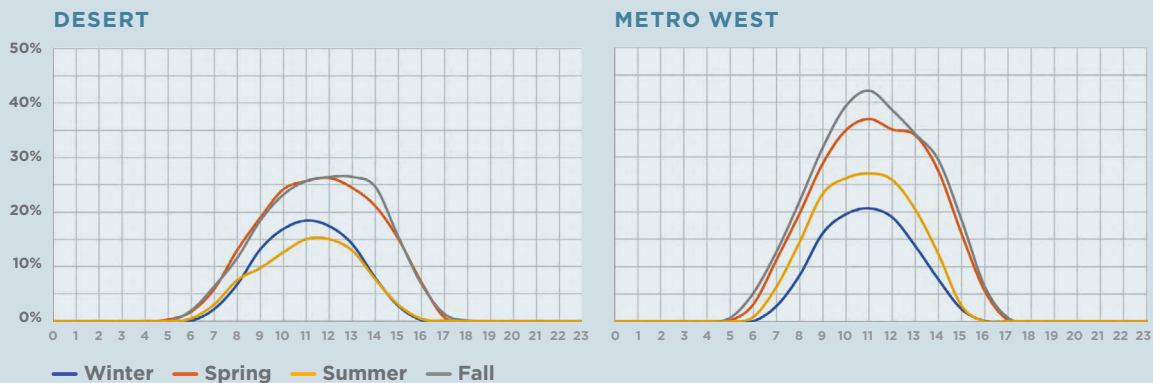


FIGURE 5. SCE 2025 Regional Dependable PV Output Profiles (as a % of Nameplate) by Hour and Season

Because of the modular nature of the electric end-use equipment, electrification-related loads can often be constructed faster than similarly sized traditional loads. As a result, the pace of anticipated growth may be very rapid and needs may emerge faster than distribution system upgrades can be constructed. Planning process modifications such as extending forecast windows or lowering the threshold where the investment analysis and design process begins can help utilities be prepared for faster growth. When considering lowering planning thresholds (e.g., identifying a planned mitigation when the forecast shows 90% loading, rather than 100%), it is important to remember that identifying a potential investment earlier does not necessarily mean that construction has to start earlier as well. Having a better sense of future needs can inform better holistic decision-making, with the actual construction of the solution timed to minimize risk while meeting system needs and maximizing the efficient sizing and deployment of upgrades.

22 SCE Dependable PV Analysis (2025 Rate Case, p. 82-89): <https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/A2305010/7166/528468078.pdf>

While identifying individual grid needs is critically important, it is also beneficial to consider the overall number of upgrades anticipated to be needed and their corresponding costs, as there may be limitations that could be addressed by proactive planning and investment. There are resource limitations and physical system configuration limitations that may constrain the number of upgrades that can be constructed in any given year. Concentrating investments over a short time period can also create undesirable increases in customer rates. Proactive investments can be utilized where these issues are expected in order to spread out construction and avoid resource bottlenecks and undesirable investment spikes.

SOLUTION SCOPING, SIZING, AND TIMING

► KEY QUESTIONS DISCUSSED IN THIS SECTION

- Once a need is identified, what kinds, and sizes of solution(s) should be deployed?
 - How does proactive investment decision-making differ from more traditional project scoping?
-

Once system needs have been identified, the next step of the planning process is to develop optimal solutions to address them. In effect, the goal of this process is to decide between a variety of potential capacity solutions with different cost and benefit profiles. For each identified distribution constraint, specific system modifications are designed and equipment is sized to meet anticipated system needs. Incorporating proactive planning and investments into this process generally extends the time window being considered further into the future. While the primary focus for distribution planning is meeting system capacity needs, solutions at a given location should be considered holistically and reflect local asset health, reliability, or other needs.

When developing proposed capacity solutions that may be deployed as proactive investments, solution sizing is a key consideration. When a system component is being upgraded and significant growth is anticipated further out in the forecast, increasing the size of the new equipment to account for expected loading throughout its entire useful life can prevent the need to revisit that location in the future, improving overall investment efficiency. In addition, non-wires solutions and other DER-based approaches may be considered for their ability to provide capacity in smaller increments, where practical. Distribution system upgrades tend to be “lumpy” and align with standard equipment sizes, which may provide more capacity (and more corresponding cost) more quickly than it is actually needed. Smaller incremental DER-based investments can be sized according to anticipated needs and added in step with actual load growth, rather than as a single large investment. This incremental approach can help mitigate risks of deviations from the forecast in future years by delaying the need to make a decision on a single large investment until the needs are more certain. Longer-term forecasts can help improve the feasibility of DER-based solutions by identifying needs far enough in advance to enable effective procurement.

When designing solutions for proactive investments, it can be beneficial to understand the full range of benefits provided by a particular solution, as other benefit streams beyond future capacity may be useful for prioritizing or selecting proactive investment opportunities. Examples of investments that provide multiple types of benefits may include

- replacing a substation transformer with a larger, higher capacity unit that also provides asset health benefits because the old asset is replaced and the new asset is at the beginning of its useful life;

- ▶ adding a second substation transformer to a substation that increases capacity and provides a redundant source if the existing transformer fails or requires maintenance;
- ▶ constructing a new substation that provides new capacity and improves both system redundancy and reliability by reducing customer outage exposure and providing an alternate source to existing infrastructure.
- ▶ Where load-serving capacity and DER hosting capacity are constrained by the same asset(s), a single investment may increase both at once.

Meeting anticipated capacity needs remains the primary focus and justification for the investment, but considering other project benefit streams can reduce the overall risk or improve a project's overall viability.

As discussed previously, DER adoption forecasts can be considered a capacity solution when they increase the load-serving capacity. When DER growth is considered in this manner, actual adoption rates should be monitored to ensure that DER adoption is occurring as expected, especially in areas with forecast constraints. Utility programs and incentives for locational and performance-based DER value, where implemented, can help to achieve capacity benefits by directing customer DER deployment to areas with anticipated needs where DER can be most beneficial to the distribution system.



PROJECT EVALUATION AND PORTFOLIO OPTIMIZATION

► KEY QUESTIONS DISCUSSED IN THIS SECTION

- How can proactive planning solutions be evaluated and selected for funding within a wider portfolio of potential utility investments?
 - What factors may be considered to assess or mitigate the increased risk of under-utilization of proactive investments?
-

Once a specific proposed solution is identified and scoped by the planning engineer, it then must compete for funding against other potential utility investments that address other grid needs. Project evaluation and portfolio optimization are the utility processes that convert the set of planning needs and proposed solutions, along with other utility capital and operational drivers, into a specific set of investments to be pursued and constructed. Within this process, generally the intent is to maximize benefits while operating within budget limitations and compliance requirements across the entire set of utility needs and responsibilities. As a result, even projects with net benefits may not be pursued if other projects provide higher degrees of benefit or require lower costs. Effectively integrating proactive planning within this process requires the ability to compare the benefits and risks of proactive investments against other more traditional investments in reliability, asset health, or other categories.

Because proactive investments come with additional risk of under-utilization (relative to investments identified via the traditional process), it is critical to clearly identify why the proactive process is the right choice for a particular investment and why the additional benefits of pursuing a proactive investment offset the additional risk. Incorporating the specific drivers for proactive investments (as explored in Chapter 2) helps to assess the specific benefits that result from using the proactive process and enables comparison with risks and benefits provided by other projects within the utility's portfolio of potential investments.

As discussed previously, considering other benefits provided by individual projects is an important factor in deciding whether a proactive project should proceed and whether it can effectively compete with other investment options. Other factors that may be relevant for prioritizing and selecting proactive investments may include equity-driven needs in historically disadvantaged areas or alignment with state policy goals and requirements. Each jurisdiction can tailor its proactive investment evaluation criteria to reflect the relative importance of these other benefits, in line with the overall objectives of pursuing proactive investments.

CHAPTER 4.

REGULATORY APPROVAL, COST RECOVERY, AND RISK MANAGEMENT

From a regulatory perspective, the fundamental challenge with proactive investments is that they are made in anticipation of future demand, which creates a potential mismatch between utility costs and revenues. This mismatch, a form of regulatory lag,²³ is neither a new phenomenon nor entirely undesirable. In fact, many utilities currently plan and invest in their distribution systems proactively, at least to some extent. Existing approaches to ratemaking and managing investment risks may continue to provide a workable framework for proactive investment. However, if the total scale of proactive investment is sufficiently large, changes in ratemaking and risk management may be necessary.

This chapter:

- ▶ discusses considerations for whether changes in ratemaking—specifically regulatory approval and cost recovery—and risk management might be necessary to support proactive investment;
- ▶ examines potential changes to ratemaking, if deemed necessary, that may help to balance incentives and support objectives related to proactive investment; and
- ▶ explores potential strategies for managing the risks associated with proactive investment.

POSSIBLE CHANGES IN RATEMAKING TO SUPPORT PROACTIVE INVESTMENT

In deciding whether proactive investments require changes to ratemaking, an initial step might be to develop criteria for when changes might be warranted. These criteria could include the following:

- ▶ **Scale** – is the scale of proactive investment larger than what can be managed through existing ratemaking practices?
- ▶ **Separability** – is it practical or desirable to separate out investments that are made proactively from those that are not?
- ▶ **Investment type** – are there kinds of proactive investments (e.g., real estate acquisition or larger substations) that should be treated differently for ratemaking and risk management?
- ▶ **Investment driver** – are there proactive investment drivers (e.g., economic development or electrification policies) for which investments should be treated differently in ratemaking and risk management?

²³ 'Regulatory lag' refers to the time in between when a utility's costs change and its rates are set. In traditional ratemaking frameworks, a utility recovers the return of its capital investments in the form of depreciation expense. A utility begins incurring the cost of depreciation as to any investment when that asset enters service, but typically rates are not immediately adjusted to account for the incremental expense, so the utility must absorb the expense within its authorized revenue. Regulatory lag thus provides an incentive for efficiency, but it can also lead to cost under-recovery and lower return on equity for utilities. This chapter assumes that readers have a basic understanding of ratemaking principles and practices. For an overview, see Lazar, [Electricity Regulation in the U.S.: A Guide](#).

- ▶ **Customer types** – are proactive investments that mainly accommodate certain kinds of customers, for instance larger commercial and industrial customers, appropriate for different treatment in ratemaking and risk management?

Some of these criteria may be utility-specific – for instance, jurisdictions may have differing expectations for electrification for different utilities and the ability of each to efficiently connect loads.

If the criteria²⁴ are not met, changes may not be necessary, implying that utilities should be able to make distribution investments – whether proactive or not – that connect new loads in a timely, cost-efficient fashion with at most only minor changes in ratemaking or with targeted changes in utility incentives. For instance, if the investment driver is related to delays in connecting new customers in a higher growth environment, then developing discrete utility performance incentives for customer connections may be a more direct way of improving utility performance, without the need to make more fundamental changes to ratemaking practices.

If the criteria are met, changes may be necessary. In this case, regulators will need to decide whether to make changes in existing ratemaking practices or whether to create a new proceeding dedicated to proactive investment. For either approach, regulators will need to decide whether utilities should be required to adopt new risk management practices for proactive investments. Figure 6 provides a visual summary of this decision-making process.

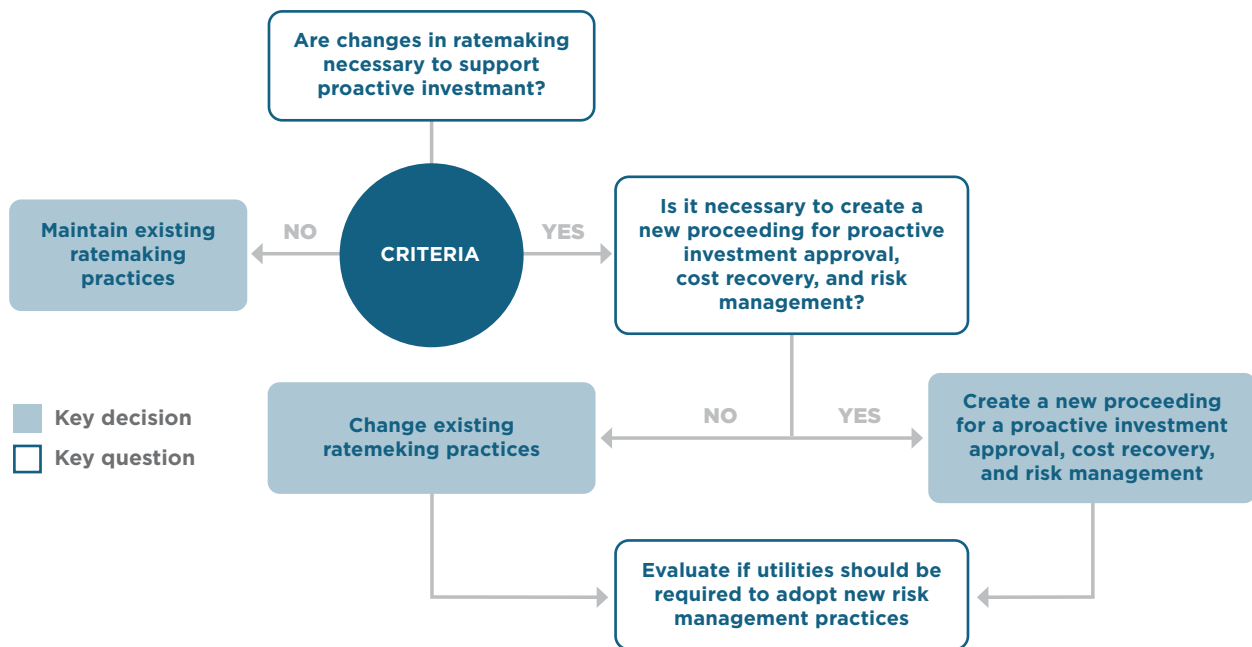


FIGURE 6. *Decision-Making Process for Changes in Ratemaking and Risk Management for Proactive Investment*

²⁴ Further analysis and discussion would be needed to develop a comprehensive list of criteria, and what it means to meet or not meet each of those criteria.

CHANGING EXISTING RATEMAKING PRACTICES

Utilities recover their costs through rates. From a simplified perspective, rates multiplied by customer consumption equal utility revenues. Rates are set based on utility costs, in the form of an annual revenue requirement, divided by some measure of consumption and the number of customers.²⁵ Regulators approve costs that are allowed to be placed into the utility revenue requirement and recovered from ratepayers. Costs are approved and rates are set through rate cases.

The mechanics of this ratemaking process differ substantially across states, but at a high level there are two general approaches to ratemaking in the U.S.:

- ▶ **Multi-year rate plans**, in which rate cases can occur on a fixed cadence, often with rates set based on a projection of future costs, an index-based formula, or a hybrid of the two that result in adjustments to base rates each year of the multi-year rate plan
- ▶ **Utility-requested rate cases**, in which utilities request rate cases when necessary to rebalance costs and revenues with a single base rate adjustment, typically to increase rates in response to rising costs

Both of these approaches often have additional mechanisms to adjust rates or revenues between rate cases, referred to as ‘interim adjustment mechanisms’ in this chapter. For instance, the most common form of interim adjustment mechanism is a fuel adjustment clause, which allows utilities to pass on changes in fuel costs to ratepayers without going through a rate case. Any changes in ratemaking to support proactive investments will depend on what kind of ratemaking practices are currently in place.

Multi-Year Rate Plans

Multi-year rate plans are designed to reduce the frequency of rate cases and provide incentives for utilities to manage costs between rate cases.²⁶ Jurisdictions with multi-year rate plans typically conduct rate cases to “re-base” rates every three to five years. The rates in multi-year rate plans are often based on projections of historic costs or future cost estimates. A plan with rate cases every four years, for example, might set costs in the 2025 rate case based on a projection of costs from 2025 through 2028.

Multi-year rate plans may already be able to support proactive investment, if proactive investments are included in the cost forecast or can be accommodated within the index-based formulas for the current rate cycle. For instance, a utility with a four-year rate plan that is projecting sustained load growth from 2025 to 2035 may propose to upsize substation transformers to accommodate longer-term growth. If the cost of the transformers is already included in its 2025 cost forecast, the utility will be able to recover the costs of forward-looking investments with limited to no regulatory lag. Regulators can adjust the time horizon of the multi-year rate plan or the costs used to set rates, in order to balance incentives and risks associated with proactive investment.

Including proactive investments in cost forecasts does, however, create risks for both ratepayers and utilities, due to uncertainty around longer-term load growth. Regulators and consumer advocates may wish to see utilities meet certain requirements (e.g., having longer-term planning processes) or institute performance incentives (e.g., risk sharing mechanisms) before allowing utilities to include proactive investments in cost forecasts for multi-year rate plans.

²⁵ The annual revenue requirement includes annual depreciation, annual return on capital, operations and maintenance (O&M) costs, and taxes. The most common measure of consumption is energy (kWh), in volumetric rates, but many rates have a fixed component (a per month customer charge) and, for larger customers, a demand charge based on the customer’s peak consumption.

²⁶ See RMI’s report “Fixing Multiyear Rate Plans” for further insights: <https://rmi.org/insight/fixing-multiyear-rate-plans/>

Regulators may want to, also, create a separate category for proactive investments within rate cases, so they can be more clearly tracked and evaluated, though doing so may create additional burdens for regulators, utilities, and stakeholders. In some cases, regulators may determine that the risks of proactive investments are better managed by creating new interim adjustment mechanisms (e.g., riders²⁷) rather than by including these investments in traditional rate base models to be recovered via cost forecasts or index-based formulas.

Regardless of approach, multi-year rate plan designs that incorporate proactive investments will need to have the same — or even more stringent — safeguards in place as those that do not, to avoid shifting risks to ratepayers. Strategies to manage risk are discussed in more detail below (“Developing New Approaches to Risk Management”).

When combined with longer-term distribution planning processes, multi-year rate plans can provide regulators and utilities with transparency and flexibility to manage proactive investments. The utility’s distribution plan provides forecasts of longer-term load growth, ideally using transparent methods, and identifies the scale and timing of investment needs. On this basis, regulators, utilities, and stakeholders can assess the nature, scale, and timing of proactive investments in planning, providing a foundation for filings and decision-making in the rate case. Alignment between rate cases and distribution planning requires thoughtful process design, where the distribution plan can inform the rate case and the rate case can inform the distribution plan. Figure 7 illustrates how the timing of distribution system plans (DSPs) and general rate cases (GRCs) could interact, in a case where a utility has a 10-year DSP that is refreshed every two years and a 4-year multi-year rate plan.

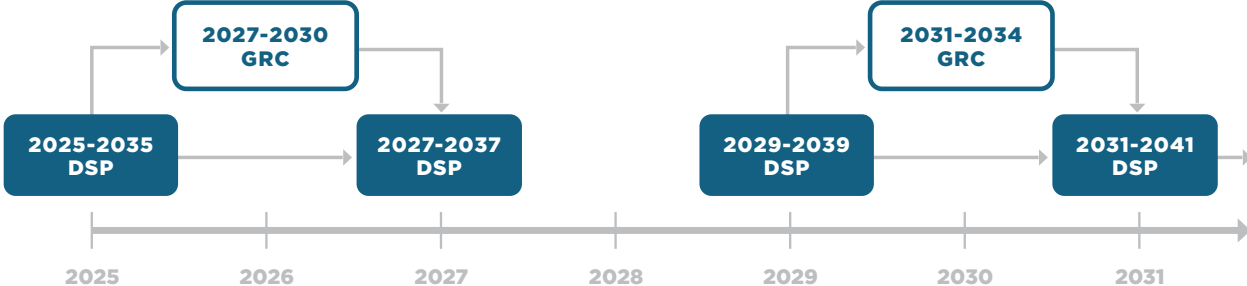


FIGURE 7. Illustration of Alignment Between Distribution System Planning (DSP) and General Rate Cases (GRCs)

Utility-Requested Rate Cases

Ratemaking in jurisdictions that have utility-requested rate cases varies significantly across the U.S. Some jurisdictions use historical costs to set rates, whereas others use cost projections; some have frequent rate cases, whereas others may go several years without a rate case; some may make copious use of interim adjustment mechanisms, whereas others may use them only sparingly.

²⁷ A rider is a separate line item on customer bills, allowing utilities to recover certain types of costs without the need to place costs into the annual revenue requirement.

Whether proactive investments present challenges for utilities in this kind of regulatory environment will depend on costs and load growth. If utilities have headroom in rates,²⁸ they may invest proactively without changes in rates. However, if proactive investments create cost pressures that require changes in rates, regulators and utilities may need to either increase rate case frequency or develop new interim adjustment mechanisms to recover the cost of proactive investments.

The most straightforward approach to interim adjustment mechanisms for proactive investments would be through the creation of riders. For proactive investments, a rider should arguably be limited to only certain pre-defined kinds of investments (e.g., larger strategic investments or investments that meet specific policy goals). Riders can be used as a temporary holding account for proactive investments between rate cases; at the next rate case, the rider amount returns to zero and costs that are deemed prudent enter into the revenue requirement and base rates.

A primary concern with riders is that they can shift risks from utilities to ratepayers, which may require caps or other incentive mechanisms to balance utility and ratepayer risks. Proactive investments that are recovered through riders could also provide utilities with lower returns, given that riders reduce utility risk.²⁹ Depending on the scale of proactive investment, developing multi-year rate plans may be a better alternative to creating new riders, because of the incentives for cost management inherent in well-designed multi-year rate plans.

CREATING A NEW PROCEEDING

Regulators and utilities may determine that existing ratemaking processes are not fit for purpose with proactive investments, and that a new proceeding is needed. Several states have taken a similar approach for grid modernization, creating separate proceedings to evaluate and approve grid modernization investments and programs.

A separate proceeding, or proceedings, for proactive investments could be focused on specific kinds of investments (e.g., only investments driven by electrification or larger loads). It would provide additional flexibility (e.g., creating associated regulatory mechanisms such as performance metrics) and transparency — proactive investments could be clearly identified and approved, with clear guidelines on timing and how risks would be managed. But for staff-constrained commissions and utilities, this flexibility and transparency may come with a high regulatory burden. In many cases, it will likely be better to first attempt to integrate proactive investments into existing ratemaking proceedings rather than to create a new proceeding.

DEVELOPING NEW APPROACHES TO RISK MANAGEMENT

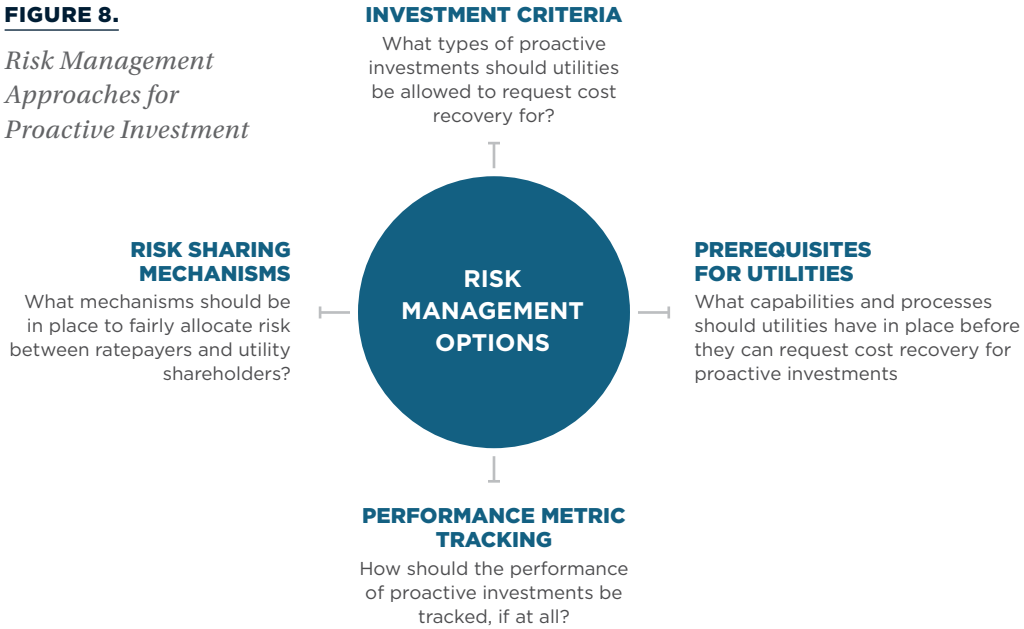
In cases where proactive investments create significant new risks for ratepayers, regulators may wish to develop new approaches to managing risk. Broadly, these new approaches might include four categories: (1) criteria for proactive investments, (2) prerequisites for utilities, (3) performance metric tracking, and (4) risk sharing mechanisms (Figure 8).

²⁸ Headroom in rates refers to when utility costs are lower than the revenues it recovers through rates over some time period. In this situation, utilities can still meet or exceed their target returns while investing in infrastructure to meet longer-term growth. The high load growth, declining average cost environment of the U.S. electricity industry before the 1970s is illustrative of this kind of situation. During this era, rate cases were uncommon.

²⁹ Rate riders reduce regulatory lag which reduces the utility's risk of cost recovery. This reduction in risk can be reflected with a lower return on equity.

FIGURE 8.

*Risk Management
Approaches for
Proactive Investment*



Criteria for Proactive Investments

By establishing clear criteria for the kinds of proactive investments for which utilities are allowed to request cost recovery, regulators can limit ratepayers' exposure to the risk that load does not materialize. For instance, limiting proactive investments to those that are determined to be least-regrets can reduce reliance on a scenario or customer type as the driver of investment needs (see discussion in Chapter 3). Criteria for proactive investments would likely vary across jurisdictions but could include:

- ▶ Least-regrets investments, determined using scenario analysis
- ▶ Equipment type, voltage level, or cost threshold
- ▶ Equipment age (for targeted replacements)
- ▶ Policy drivers
- ▶ Customer types

To be useful, investment criteria would need to balance simplicity, effectiveness, and flexibility.

Prerequisites for Utilities

Regulators may require utilities to have certain capabilities or processes in place—prerequisites—before regulators consider cost recovery for proactive investments.

These prerequisites might include the following:

- ▶ Regular, transparent, well-structured distribution system planning processes
- ▶ Clearly documented, scenario-based load forecasting methods that meet some of the standards discussed in Chapter 3
- ▶ Regular reporting of long-term load forecast error
- ▶ Least-regrets methods for needs identification
- ▶ More extensive screens for load flexibility, flexible connections, and non-wires alternatives

- ▶ Rates and harmonized programs that provide incentives that could mitigate investment needs over the longer term
- ▶ Clear and timely public communication of where headroom exists on the system to connect new loads at low cost
- ▶ Platforms for sharing distribution load and network data with regulators, developers, and other stakeholders

The elements above reduce the risks of proactive investments by improving long-term load forecasting, limiting the scope of proactive investments, reducing the need for proactive investments, and increasing stakeholder buy-in.

Performance Metric Tracking

Performance metrics can be broadly utilized to ensure utility performance across key indicators, including policy goals and cost containment, among other areas. A subset of these performance metrics could consider proactive investment, which could include customer connection times, customer costs, flexible service connection offerings, asset utilization, forecasting accuracy, and reliability. For example, did the load growth that the utility forecasted materialize?

For larger distribution equipment, utilization is straightforward to measure and the load data to do so is often already available to utilities. However, unlike for power plants or larger transmission lines, there is little to no precedent for benchmarking, tracking, and assessing performance for distribution equipment in the United States, in part because there are a large number of circuits which makes tracking more of an undertaking, and performance can be situation specific due to different system configurations and levels of granularity that can be measured.

As a result, it may be difficult to determine what a satisfactory utilization range for proactive investments should be, relative to traditional investments. For jurisdictions that wish to track utilization of proactive investments, an initial step may be to benchmark and track performance of existing investments. Performance metrics could differ in terms of their scope and granularity, evaluation periods, and metric values. The metrics values in Table 3 could be based on individual investments or, perhaps more realistically, a portfolio of investments.

TABLE 3. *Options for Performance Metric Design (non-exhaustive)*

CATEGORIES OF METRICS	MEASUREMENT OPTIONS
Scope and granularity	<ul style="list-style-type: none"> • Equipment type • Individual investments or portfolio average
Timing	<ul style="list-style-type: none"> • Single period (metric evaluation after a specified number of years) • Multiple periods (metric evaluation annually or at fixed intervals) • Rolling average (rolling average over time)
Metric values	<ul style="list-style-type: none"> • Load forecast accuracy (%) • Annual or monthly peak utilization (peak MW / capacity limit) • Average annual or monthly capacity factor (MWh/MW capacity/annual or monthly hours) • Combination of peak and average utilization



This is a subject that is not well developed but could be important for successful application of proactive investment frameworks, and requires more investigation.

Risk Sharing Mechanisms

Traditionally, regulators have relied on “used and useful” evaluation and cost disallowance as means to limit ratepayer risk for utility investments. If investments are not deemed used and useful, regulators can deny cost recovery for the associated investments. In practice, distribution investments are rarely deemed to not be used and useful and cost disallowance for these investments tends to be uncommon.³⁰

An alternative might be to set ex ante, rather than ex post, risk sharing mechanisms. Ex ante mechanisms could be milestone based, limiting cost recovery or tying utility financial returns to performance metrics. Other approaches to ex ante risk sharing might be tied to the design of riders or the cost forecasts or index-based formulas used in multi-year rate plans, discussed above.

In all of these cases, risk sharing mechanisms aim to provide an upside to utilities, by enabling proactive investment with some level of increased certainty for cost recovery, while limiting the downside risk to ratepayers. Creating risk sharing mechanisms only for proactive investments requires careful design to avoid unintended consequences, as these mechanisms may distort utility investment incentives if they are overly generous or overly punitive relative to traditional investments.

Risk sharing mechanisms are an important and emerging topic that will require more development to support proactive investment processes in the future.

30 There is limited empirical evidence on utility cost disallowance. This statement is based on the collective professional experience of the CHARGED team.

FRAMEWORKS FOR PROACTIVE INVESTMENTS IN PRACTICE

Several jurisdictions have explored regulatory frameworks for proactive investments.

TABLE 4. *Example Draft or Final Proactive Investment Frameworks*

STATE	DOCUMENT NAME	DATE	DESCRIPTION
Massachusetts	Framework for the Long Term System Planning Process for Distributed Generation ³¹	May 9, 2025	A framework for identifying areas on the distribution system to make proactive investments to enable DER related connections.
Minnesota	In the Matter of a Commission Inquiry into a Framework for Proactive Distribution Grid Upgrades and Cost Allocation for Xcel Energy ³²	April 7, 2025	Development of a framework for proactive investments for both load and DER capacity, with specific investments proposed within the Integrated Distribution Plan (IDP). Phase 1 focuses on addressing needs driven by residential and smaller commercial load and DER growth.
New York	In the Matter of Proactive Planning for Upgraded Electric Grid Infrastructure - Order adopting modified proactive planning framework ³³	September 18, 2025	A framework to enable the utilities to identify and seek authorization for the grid needs driven by electrification for which proactive investment would improve cost-effectiveness, minimize ratepayer impacts, and support policy outcomes.

31 D.P.U. 25-30 - Attachment A, Framework for the Long Term System Planning Process for Distribution Generation, May 9, 2025, <https://fileservice.eea.comacloud.net/V3.1.0/FileService.Api/file//aechfbcaj?H2WP7YvZfmq7ZJ9JSMx8IDVOcWnmqkF7a2iSbK4sRtaPcSxl+blU344Kxhm+qpOegOhKFj9M9l/xQR8+/8GqPvdGgrFe6XR6nglfa80wd3rxFD8G4j981M2Rna9aVTXA>

32 PUC Docket Number: E002/CI-24-318, In The Matter of a Commission Inquiry into a Framework for Proactive Distribution Grid Upgrades and Cost Allocation for Xcel Energy, April 7, 2025, <https://efiling.web.commerce.state.mn.us/documents/%7BE0831096-0000-CD13-930C-1797E172AFFA%7D/download?contentSequence=0&rowIndex=1>

33 State of New York Public Service Commission, Case 24-E-0364, In the Matter of Proactive Planning for Upgraded Electric Grid Infrastructure - Order adopting modified proactive planning framework, September 18, 2025, <https://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterSeq=73733>

CHAPTER 5.

COST ALLOCATION

This chapter addresses cost allocation considerations with the underlying assumption that proactive investments are fully coordinated and sequenced through an integrated planning process. Under this approach, capital is deployed ahead of immediate demand, sequenced with enabling infrastructure, and designed to meet anticipated policy and reliability objectives. Such forward-looking investments create unique cost allocation challenges as the benefits may accrue unevenly in early years of investments. Key questions include how these costs should be allocated across customers, and which parties should be responsible for paying the costs of any proactive investments that are under utilized.

In principle, there are many potential ways to allocate proactive investment costs, some innovative and new, some simple but tried and true. In practice, cost allocation is often controversial and regulators may find it more practical to use existing cost allocation methods for proactive investments rather than to develop new approaches. The primary questions around cost allocation for proactive investment involve the degree to which these costs should be allocated to the anticipated new loads that cause them or socialized across a broader base of customers. Even if regulators maintain status quo allocation, stakeholder dialogue on cost allocation methods may be helpful for creating buy-in and consensus.

This chapter provides a framework for considering methods for allocating proactive investment costs. The discussion aims to be comprehensive rather than prescriptive, recognizing that different jurisdictions have different philosophies around cost allocation and that what might be a change in one jurisdiction is already in practice in another.

COST ALLOCATION MODELS FOR PROACTIVE INVESTMENTS

There are three main actors in the cost allocation calculus for proactive investment:

- ▶ **Participants** – a customer or customers that cause or primarily use investments
- ▶ **Non-participants** – customers that do not trigger investments or are at most limited users
- ▶ **The distribution utility and its shareholders**

The participant / non-participant language is drawn from utility programs, such as demand-side management programs, and provides a rubric for discussion, though as discussed below there are limits to its application for proactive investment.

Cost allocation models for proactive investment lie along a spectrum between participant funding and cost socialization, in which there is no distinction between participants and non-participants. In between these two bookends are cost sharing arrangements that explicitly allocate costs between participants and non-participants. Figure 9 illustrates the three general models along this spectrum.

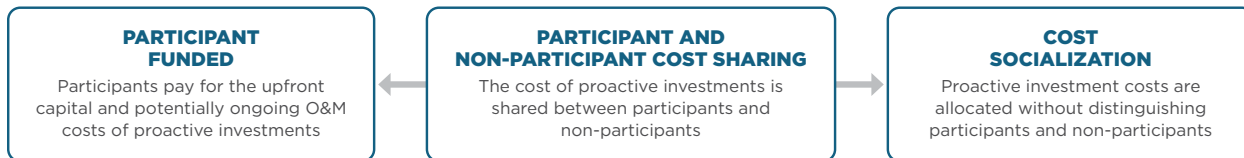


FIGURE 9. *Spectrum of Cost Allocation Models for Proactive Investment*

Each of the three models has multiple possible designs, with different approaches to cost recovery and different incentives and risks for participants, non-participants, and the utility.

The remainder of this chapter describes potential approaches to allocation methods for each of the three models. In addition to model-specific considerations, there are also several other high-level issues for cost allocation that are useful to consider.

Other Higher-Level Considerations

- ▶ **Targeting approaches.** Regulators and utilities may wish to use different allocation models for different kinds of proactive investments. If so, an initial step may be to develop a framework for how different kinds of costs would be allocated. For instance, commissions may decide that investments driven by larger loads will be paid for through a tariff (see “Participant Funding” section, below), or that the costs of larger, higher voltage equipment will all be socialized. The choice of cost allocation models will also be shaped by practical considerations — in some cases, it may be very clear who the participants are (e.g., a substation built to accommodate heavy-duty vehicle fleet charging in a specific location), whereas in other cases it may be difficult to identify individual participants (e.g., a substation built proactively to accommodate future load growth in an economic development area), and in some cases it may not be possible to identify participants at all.
- ▶ **Timing and incentives.** Cost allocation methods differ in terms of the time horizon over which investments are paid for, ranging from upfront payments to repayment over the expected lifetime of the asset. Differences in the timing and structure of payments can create significant differences in incentives for load flexibility. For instance, customers that pay upfront for network upgrade costs will generally have a much larger incentive to select and size equipment in ways that reduce their capacity needs (including the use of flexibility) compared to customers that instead pay for costs over the lifetime of equipment through volumetric rates.
- ▶ **Non-DER and DER-related investments.** The design of mechanisms for cost allocation, cost recovery, and risk management for proactive electrification-driven distribution upgrades will overlap with those for proactive DER-driven upgrades, and so it will ultimately be important to consider the design of these mechanisms for both purposes in tandem. Still, it may be helpful to think about the regulatory mechanisms separately in the early stages of conceptualization to simplify the number of variables.
- ▶ **Distribution and transmission investments.** Proactive investments might include both distribution and transmission infrastructure, which could have different cost allocation methods. The focus in this chapter is on distribution costs.

PARTICIPANT FUNDED MODEL

In the participant funded model, either a single customer or a group of customers pays for proactive investments. Under different mechanism designs, ratepayers or the utility may be

exposed to residual costs that are not paid for by participants. Limiting this exposure may require pre-emptive strategies, such as transparency in the amount of these costs that utilities hold on their books and a cap on the total amount of unfunded investment.

Table 5 describes three possible designs of a participant funded model, based on how participants pay for upfront costs. In the first design (participant pays), customers request proactive investments — for instance a new manufacturer may request that upgrades are completed and pay for them significantly in advance of when it expects to begin operations — to provide flexibility. This first design is consistent with capacity reservation. In the second design (direct assigned), the utility identifies upgrades — for instance in a long-term plan — and funds the construction, but allocates the entire costs to the customer(s) that will use the upgrade, with those customers repaying the utility upfront. An example could be infrastructure to support higher power EV charging (e.g., DC fast chargers). In the third design (tariff/fee), the utility identifies upgrades and allocates the costs through a tariff on participants, with costs recovered over a longer time horizon.

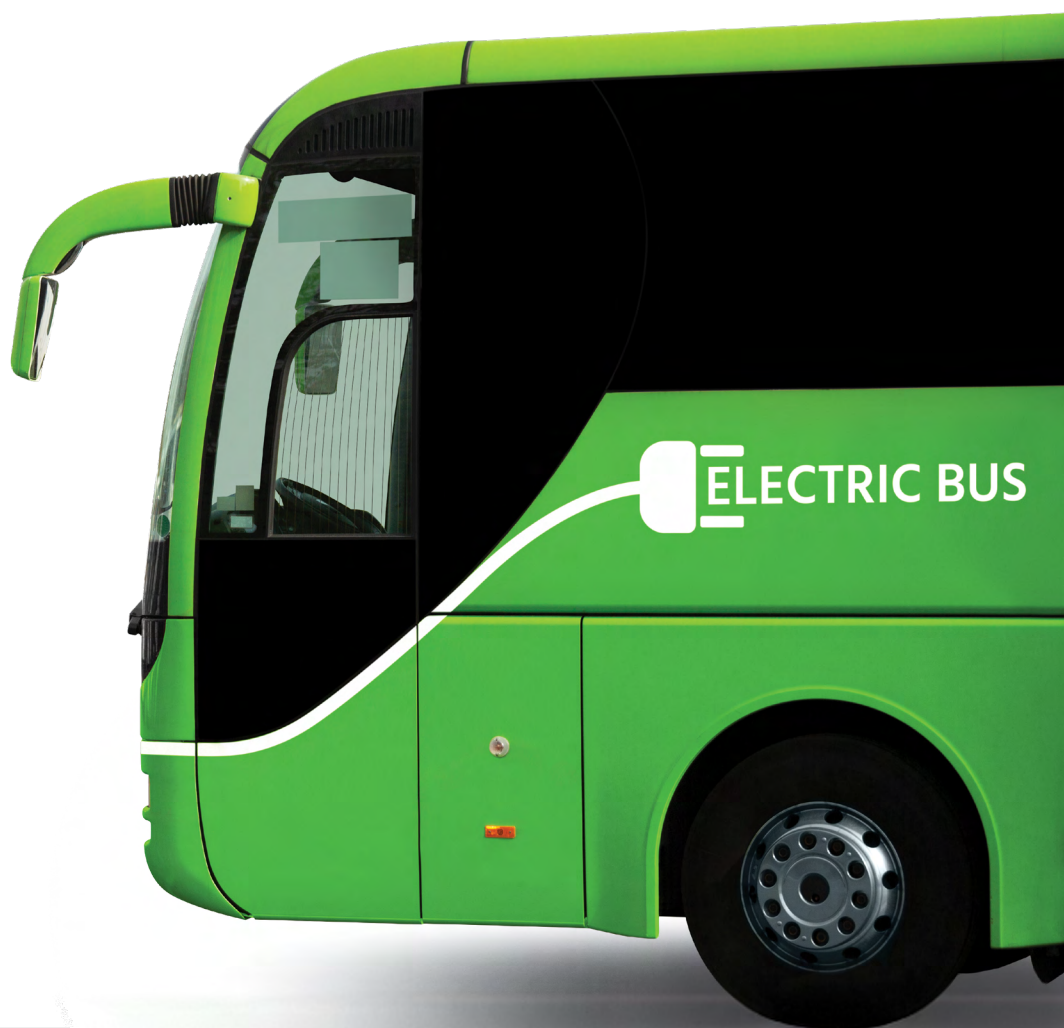


TABLE 5. *Design Options for Participant Funding of Proactive Investments*

PARTICIPANT FUNDING OPTION	DESCRIPTION	DESIGN DETAILS
Participant pays	Participants pay all upfront costs at the outset	<ul style="list-style-type: none"> • Customer(s) requests upgrades • Requesting customer(s) directly pay for full upfront costs of construction and equipment • Asset value not included in utility rate base • Utility owns the asset and is still responsible for O&M • Requesting customer(s) or utility may pay for O&M costs • No risk to non-participant utility customers for capital costs, may be some risk for O&M
Direct assigned	Utility funds construction and participants repay utility for all upfront costs at the outset	<ul style="list-style-type: none"> • Utility identifies upgrades • Utility pays for upfront costs, directly assigns costs to customer or customers that use the upgrade • Direct assignment could be: (a) fully to the first customer that uses the upgrade (first mover pays), (b) fully to the initial customer with a mechanism for later-in-time customers that use the upgrade to refund earlier-in-time customers • Asset value not included in utility rate base • Utility owns the asset and is still responsible for O&M • Participant(s) or utility may pay for O&M costs • May be risk to utility customers if no customers use the upgrade, may be some risk for O&M
Tariff/fee	Participants pay a portion of upfront costs at the outset or over time	<ul style="list-style-type: none"> • Utility identifies upgrades • Utility pays for upfront costs, creates a tariff for participants to pay for upgrade costs over time; tariff could be (a) a one-time fixed charge (e.g., \$/customer), (b) an ongoing fixed charge (e.g., \$/customer-yr), or (c) a usage fee (e.g., \$/kW-yr or \$/kWh) • Tariff/fee could be more or less spatially granular; (e.g., if combined with cost sharing, could be zonal on all new loads) • Asset value may be included in rate base while it is being repaid • Utility owns the asset and is still responsible for O&M • Participant(s) or utility may pay for O&M costs • Utility and/or non-participant customers assume the risk that revenue from the tariff will equal or exceed costs • Regulator may have mechanisms to disallow costs or limit what goes into rate base if tariff revenues or utilization fall below a certain, ideally predefined, level

There is often consensus that the participant funded model should be limited to larger commercial, industrial, and large residential customers (e.g., housing developers) — whereas it is more efficient to socialize costs for smaller residential and commercial customers.

COST SOCIALIZATION MODEL

In the cost socialization model, proactive upgrade costs are allocated to all load, including both participants and non-participants. The incorporation of these costs in rates could be more or less targeted. Targeting could be by certain customer classes/rates, voltage classes, and/or locations, and could be more or less time granular.

Most utilities already have ratemaking processes that facilitate some targeting of costs in rates through:

- ▶ **Functionalization** – separation of costs into shared and non-shared costs and then assignment of costs to functional categories (distribution, transmission, generation, administrative); non-shared costs may be directly assigned
- ▶ **Classification** – assignment of costs by causal factors (capacity, energy, customer)
- ▶ **Allocation** – assignment to customer classes (residential, commercial, industrial) using allocation factors

To enable more targeted cost allocation, regulators could also create new categories of customers (e.g., very large loads with high load factors, large loads with lower load factors). Table 6 below describes different potential approaches to targeting; several of these could be used in tandem (e.g., allocate by location, voltage level, customer type, and time-of-use).

TABLE 6. *Design Options for Targeted Cost Allocation in Rates*

COST ALLOCATION APPROACH	DESCRIPTION
Non-targeted (shared costs)	Lump proactive upgrades with other standard costs and allocate costs according to normal ratemaking rules
Location	Allocate proactive upgrade costs to zones or sub-zones where the upgrades are made
Voltage levels	Allocate costs to customers connected at voltages for which the upgrades is likely to be most highly used, if this does not already occur under “non-targeted” designs
Customer type	Allocate costs to customer classes that are most likely to use the upgrades
Time-of-use	Allocate costs to times at which the upgrades are likely to be most highly used or coincide with marginal cost drivers

Targeting cost allocation of proactive investments to participants (cost causers) may be attractive in principle, but it is worth noting that there are tradeoffs to doing so in terms of complexity, constraints to growth, and unintended consequences. These tradeoffs are not different from those for traditional (non-proactive) investments.

For both more and less targeted approaches to rate design, participants and non-participants will have some exposure to the costs of under-utilized investments. Potential risk management mechanisms are discussed in Chapter 4.

COST SHARING MODEL

In the cost sharing model, participants and non-participants share the costs of proactive upgrades based on preset formulas or analysis of costs and benefits. Cost sharing models could be applied to any approaches in the participant funded model or cost socialization model.

The main decision point for cost sharing is how the split between participant and non-participant costs is determined, as per Table 7. Many jurisdictions already have cost sharing for line extensions in the form of contribution in aid of construction (CIAC) mechanisms, in which connecting customers pay for some costs but receive credit or repayment based on a preset formula or an analysis of the extent to which adding the customer’s load would reduce rates or costs for other

customers. CIAC-like mechanisms for cost sharing may be more difficult to use for some kinds of proactive investments because CIAC is a form of direct cost allocation that requires a known and current customer.

TABLE 7. *Design Options for Cost Sharing*

COST SHARING APPROACH	DESCRIPTION
Fixed share	<ul style="list-style-type: none"> • Cost sharing is based on a fixed allocation (e.g., 50%-50%) between participants and non-participants • Fixed percentages could be based on analysis of approximate cost causation or benefits sharing • Fixed amount could be based on participant load
Consider cost causation and beneficiaries pays principles	<ul style="list-style-type: none"> • Each investment or portfolio of investments undergoes analysis to determine cost share percentages, for instance based on how much non-participants benefit from the new load or from the upgrade • Benefit-cost analysis could be more like CIAC or, for larger equipment, could use power flow analysis to estimate and allocate based on peak use • Cost share percentages could change over time, based on regular studies

For network upgrades that are closer to the point of customer connection to the distribution system, it may be easier to identify participants (cost causers) and allocate some costs to them. However, for proactive upgrades that are further upstream in the distribution system — such as a larger substation — it may be more difficult to identify participants and allocate costs to them.

CHAPTER 6.

CONCLUSION

Utilities should consider proactive investments in locations or situations where such investments provide specific benefits compared to the traditional process, such as long-run cost-effectiveness, faster connections for new loads, customer experience improvements, or support for state energy goals. It is essential to minimize risks in the process of making these investments including stranded or underutilized assets, unsuitable investments, inappropriate cost allocation, disallowance, and poor utility internal alignment. However, it is also important to acknowledge that current investment practices also involve risks which can be reduced by making proactive investments such as delayed energization, revenue loss or delay, missed policy objectives, suboptimal investments, inefficient investment, construction logistics challenges, and degraded reliability.

To consider proactive investments there are several essential considerations including appropriateness of proactive investments given forecasting and system capacity needs, potential changes needed in ratemaking to manage and address risk, and methods for cost allocation. In many cases, changes to existing ratemaking processes may not be required, but this will depend on the nature of the proactive investment, such as scale, customer and investment types and drivers. This report outlined considerations for making that assessment. While traditional cost-allocation principles and methods still apply to proactive investments, in some instances, it might be desirable to explore more methods that take into account future beneficiaries. However, alternative approaches can add significant complexity and care should be taken in deviating from traditional practices that have been relied on for several decades.

Developing investment criteria and performance metrics to assess proactive investments and utility performance is an essential next step to develop the necessary regulatory infrastructure for proactive investments while protecting ratepayers. Furthermore, continuing to develop prerequisite regulatory processes for utilities that want to conduct proactive investment projects is also critical for protecting customers.