Lawrence Berkeley National Laboratory

LBL Publications

Title

Effectively Considering the Distribution System in Integrated Resource Plans

Permalink

https://escholarship.org/uc/item/6pt534n0

Authors

Relf, Grace

Martini, Paul De

McAdams, Jasmine

et al.

Publication Date

2026-08-18

Copyright Information

This work is made available under the terms of a Creative Commons Attribution-NonCommercial-NoDerivatives License, available at https://creativecommons.org/licenses/by-nc-nd/4.0/

eScholarship.org Powered by the California Digital Library University of California

BERKELEY LAB

Effectively Considering the Distribution System in Integrated Resource Plans

Grace Relf, Paul DeMartini,[1] Jasmine McAdams, Lisa C. Schwartz, and Vinita Srinivasan
[1]Newport Consulting Group

August 2026

The U.S. Department of Energy's Office of Electricity supported this work under Contract No. DE-AC02-05CH11231.

Disclaimer

This document was prepared as an account of work sponsored by the United States Government. While this document is believed to contain correct information, neither the United States Government nor any agency thereof, nor The Regents of the University of California, nor any of their employees, makes any warranty, express or implied, or assumes any legal responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by its trade name, trademark, manufacturer, or otherwise, does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof, or The Regents of the University of California. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof, or The Regents of the University of California.

Ernest Orlando Lawrence Berkeley National Laboratory is an equal opportunity employer.

Copyright Notice

This manuscript has been authored by an author at Lawrence Berkeley National Laboratory under Contract No. DE-AC02-05CH11231 with the U.S. Department of Energy. The U.S. Government retains, and the publisher, by accepting the article for publication, acknowledges, that the U.S. Government retains a non-exclusive, paid-up, irrevocable, worldwide license to publish or reproduce the published form of this manuscript, or allow others to do so, for U.S. Government purposes.

Acknowledgements

The work described in this study was funded by the U.S. Department of Energy (DOE), Office of Electricity, under Lawrence Berkeley National Laboratory Contract No. DE-AC02-05CH11231.

The authors thank DOE program manager Sandra Jenkins, reviewers, and experts who participated in our interviews. Specific statements in this report do not necessarily represent the views of those who reviewed the report or participated in interviews, or their employers.

The following individuals reviewed a draft of all or portions of this report:

Mads Almassalkhi	University of Vermont
Marc Asano	Hawaiian Electric
Aaron Burdick	Energy and Environmental Economics, Inc.
Danielle Sass Byrnett	National Association of Regulatory Utility Commissioners
Juan Pablo Carvallo	Lawrence Berkeley National Laboratory
Kara Durbin	Puget Sound Energy
Julieta Giraldez	Electric Power Engineers
Elaine Hale	National Laboratory of the Rockies
Elizabeth Hossner	Puget Sound Energy
Leo Jiang	Energy Systems Integration Group
Mary Jo Krolewski	Vermont Public Utilities Commission
Michaela Levine	Energy and Environmental Economics, Inc.
Schuyler Matteson	New York Department of Public Service
Brenda McDermott	Electric Power Engineers
Sean Morash	Telos Energy
Peter Rossi	Vermont Electric Cooperative
Matthew Schuerger	Energy Systems Integration Group
Nat Skinner	California Public Advocates
Hanna Terwilliger	Minnesota Public Utilities Commission
Tyler Nam	California Energy Commission
Kirsten Verclas	National Association of State Energy Officials

Table of Contents

List of Figures

List of Tables

Acronyms and Abbreviations

BPS	**Bulk power system**
CEM	Capacity expansion model
DER	Distributed energy resource
DOE	Department of Energy
DSP	Distribution system plan
FERC	Federal Energy Regulatory Commission
GER	Grid-edge resource (also called DER)
HCA	Hosting capacity analysis
IRP	Integrated resource plan
ISO	Independent system operator
ISP	Integrated system planning
MW	Megawatt
PSC	Public Service Commission
PUC	Public Utility Commission
RTO	Regional transmission organization
T&D	Transmission and distribution

Executive Summary

Distribution spending by investor-owned utilities (IOUs) grew nationally by 6% per year since 2014 — four times faster than the prior two decades — and many utilities are planning for significantly higher spending through 2030.[1] Costs for generation and transmission also are increasing significantly.[2] Utilities across the country have for decades filed integrated resource plans (IRPs) for bulk power system assets, but there has been less visibility into distribution system spending. By considering certain aspects of the distribution system, IRPs can provide greater insight into how planned expenditures at the distribution level could cost-effectively serve both local grid and bulk power system needs.

This report aims to support public utility commissions (PUCs), utilities, State Energy Offices, state utility consumer offices, and other stakeholders to improve electric utility planning processes by identifying a range of tactical approaches to consider distribution system planning (DSP) elements in IRP to meet electricity needs at least cost.

States and utilities across the country, with varying regulatory and market frameworks, are taking meaningful steps to integrate distribution system elements in IRP, aiming to optimize grid investments, reduce utility costs and customer bills, and improve plan transparency and credibility. IRP also can serve as a vehicle for elevating the most impactful elements of distribution planning for stakeholder review and input, particularly in jurisdictions without DSP filing requirements that make that information publicly available.

While IRP and DSP address different levels of the electricity system and use different planning techniques, there are key linkages between the two types of plans:

- Using consistent forecasts, including for loads, grid-edge resources (GERs),[3] and other variables to plan for a unified vision of the future
- Assessing whether distribution system resources can help serve bulk power system needs at lower cost and, at the same time, considering local grid benefits
- Analyzing the capability of the distribution system to accommodate GERs identified as least-cost resources in IRP.

Implementing these practices requires more sophisticated analyses; communication between utility planners, the PUC, and stakeholders; and the utility's commitment to change management to support staff implementing new planning techniques. The following table summarizes leading practices to help overcome these challenges and realize the potential value of considering distribution system elements in IRP.[4]

[1] Wiser et al., 2026a.
[2] Wiser et al., 2026b.
[3] Also called distributed energy resources.
[4] The Conclusions section of the report includes an expanded checklist tool that utilities, PUCs, and stakeholders can use to assess and improve current practices.

Regulatory & Institutional Alignment
☑ Develop regulatory frameworks for integrated or coordinated system planning
☑ Align utility regulatory guidance for IRP and distribution system planning (e.g., specify expectations for consistent forecasts and scenarios)
☑ Develop a roadmap to improve practices over time and establish a common vision
Aligned Timelines & Horizons
☑ Sequence planning cycles so distribution insights (e.g., available hosting capacity) feed into IRP decisions on time, and vice versa (e.g., quantity of GERs selected in IRP)
Stakeholder Engagement & Transparency
☑ Share scenarios, assumptions, and results openly with PUCs and stakeholders to solicit input on consistency
☑ Incorporate stakeholder input from various forums into unified forecast assumptions, scenario design, and review processes
Common Data & Assumptions
☑ Establish unified methodologies, associated load and GER forecasts, and adoption scenarios across IRP and distribution planning
☑ Maintain a unified integrated data set in an accessible repository for sharing inputs and results
Disaggregated Distribution Forecasting
☑ Align IRP and feeder and substation-level distribution forecasts through a reconciliation method to capture both local and bulk system needs
Hosting Capacity & Deliverability
☑ Assess results of hosting capacity and GER deliverability studies in the IRP process to determine whether pathways exist for GERs to deliver services identified in IRP
☑ Publish hosting capacity maps/tools to guide developer siting decisions for procurements coming out of IRPs
Convergent vs. Divergent Value Analysis
☑ Screen all eligible identified electricity system needs for cost-effective non-wires alternatives
☑ Identify when, where, and how GERs provide simultaneous (convergent) benefits to bulk power and distribution needs and evaluate these potential solutions in more detail
☑ Flag cases where GERs help one level of the electricity system but not the other (divergent) and determine possible mitigations
Bulk Power & Distribution System Resource Co-Optimization
☑ Use technology-neutral procurements
☑ Include GERs as a selectable resource in IRPs and use technology-neutral methodologies for performance accreditation to allow GERs to contribute to resource adequacy assessments
☑ Incorporate findings from coordinated planning into procurement processes and validate planning assumptions for cost and performance based on procurements

1. Introduction

Electric utilities plan their systems to reliably and safely meet future needs at least cost and risk, considering uncertainties. With significant projected load growth, aging infrastructure, rapid technological advances, and increasingly severe and frequent weather events, effective planning is critical to guide utility decision-making for cost-effective investments to meet planning criteria and objectives.

Electricity planning is evolving. Utilities have long used planning frameworks developed for a power system characterized by relatively predictable demand, centralized generation, and one-way power flows. Today's grid is more dynamic. It must serve rapidly growing residential, commercial and industrial loads, new types of large loads such as data centers, accommodate growing shares of GERs such as storage,[5] and maintain reliability as electricity system assets age. Planning processes are adapting to capture the spatial, temporal, and operational complexity of evolving electricity systems.

Planning processes vary based on the type of utility and market structure in which they operate. IRP, conducted largely by vertically integrated utilities, is a "roadmap for meeting forecasted electricity demand over a specified future period, historically focused on the bulk power system [BPS]."[6] Distribution system planning (DSP) "focuses on designing, managing, and maintaining lower-voltage networks that connect end users to the larger power system."[7]

In most jurisdictions, IRP and DSP are conducted separately, on different timelines, and with distinct methods, tools, assumptions, and regulatory requirements. Increasingly, utilities and states recognize that coordinated planning across bulk power and distribution systems produces more robust and useful plans.[8] Consideration of DSP elements within IRP is growing in importance for several reasons — increased siting of distributed generation and storage co-located with loads, significant investments to manage existing distribution systems (asset replacement, safety, reliability, and resilience), and expanded bulk and distribution level capacity needs to address the impacts of economic growth, including large new loads.[9] This report details how considering distribution system elements in IRP provides value to utilities and regulatory processes. Based on a review of a variety of utility approaches, the report offers a range of actions to take to realize that value.

1.1 Study Motivation and Scope

U.S. utilities are responding to rapid changes in electricity systems, including loads that are

---

[5] GERs are assets, such as gas generators, solar, wind, and energy storage, sited close to utility customers that can provide all or some of their immediate power needs and reduce demand or provide supply to satisfy the energy, capacity, or ancillary service needs (adapted from National Association of Regulatory Utility Commissioners [NARUC], 2016).
[6] Biewald et al., 2024.
[7] Energy Systems Integration Group (ESIG), 2025.
[8] See additional resources at https://www.naruc.org/committees/task-forces-working-groups/retired-task-forces/task-force-on-comprehensive-electricity-planning/resources-for-action/; NARUC – National Association of State Energy Officials (NASEO), 2021a; NARUC-NASEO, ND.
[9] Wiser et al., 2026a.

growing at rates not seen in decades,[10] increased risk from severe weather, and growing customer technology adoption. At the same time, utility investments are facing increased scrutiny from PUCs, customers, and other stakeholders to keep electricity rates in check. Planning processes lie squarely at this intersection by providing visibility into how utilities expect to meet future needs at least-cost, considering various constraints, risks, and uncertainties.

Incorporating elements of DSP in IRP can improve utility planning outcomes, including electricity affordability and reliability. Coordination across the planning domains can enable utilities to better anticipate localized load growth, evaluate bulk system impacts of distribution-level assets, improve valuation and utilization of GERs, and optimize electricity system investments. Robust least-cost planning requires consideration of all system needs to build a system that achieves multiple objectives.

IRP is a prominent and well-established utility planning process that also can serve as a vehicle for elevating the most impactful elements of distribution planning for stakeholder review and input, including:

- Administrative and process coordination
- Load and GER forecasting
- Scenario and sensitivity analysis
- Distribution grid optimization (i.e., improving load factor — the ratio of average load to peak load — and effective GER utilization and integration)
- Integrated system analysis.

However, coordinating bulk power and distribution system planning is an emerging area and complex exercise. Utilities and PUCs need more tangible information on the value of investing in planning coordination and how to begin or improve this practice. They also can consider issues that may arise when planning processes are not coordinated. For example, IRP may identify distributed generation co-located with loads as part of the utility's preferred resource portfolio without considering the cost of distribution system upgrades that may be needed. Conversely, IRP models may not consider potential local grid benefits of distributed generation and storage and fail to select cost-effective resources connected to distribution systems.

Effective tactics for considering distribution planning elements in IRP are adaptable to diverse regulatory frameworks, electricity market structures, available energy resources, state and utility objectives, and existing planning practices across the country.[11] This report aims to help PUCs, utilities, and stakeholders identify where coordination provides the greatest value and what approaches are most feasible in particular contexts.

---

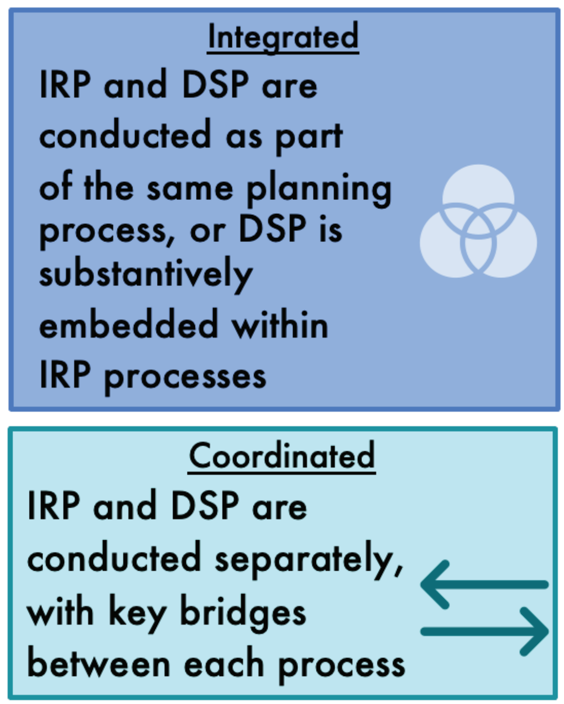
[10] Wiser et al., 2026b.

[11] For example, Salt River Project (SRP) is not regulated by a public utility commission but conducts integrated system planning. See a detailed case study on SRP here: https://eta.lbl.gov/publications/effectively-considering-distribution.

While all jurisdictions can benefit from improved planning coordination, the value of integrating distribution planning elements in IRP is particularly strong where:

- Utilities do not have formal DSP requirements and can integrate key DSP elements into the IRP to fill gaps.
- The jurisdiction requires both IRP and DSP filings, but may benefit from improved coordination, such as through structured data exchange, shared scenarios and assumptions, and iterative modeling approaches.
- Utilities are experiencing rapid growth in loads or GERs, or both, and can use integrated planning to effectively align electricity infrastructure investments with changing customer demands and contributions.
- Jurisdictions are seeking methods to identify more holistic and optimized investment strategies.

Some utilities are moving towards an Integrated System Planning (ISP) approach that considers generation, transmission, distribution, and customer resources and needs together. Other utilities conduct IRP and DSP separately, then coordinate the processes by feeding information back and forth across proceedings.[12]



Because the report addresses ways to incorporate distribution planning elements in IRP, it may be most immediately applicable to jurisdictions that have oversight over both distribution and bulk power systems — those with vertically integrated utilities. However, the information is also relevant for entities with some authority over bulk system planning, those that coordinate various plans across stakeholders, and those that incorporate the results of IRPs in other plans, such as wholesale market operators.[13]

This research does not cover transmission planning as a standalone process; it considers transmission planning only to the extent that it is included within an IRP.[14] IRPs can consider transmission needs and solutions in multiple ways. Utility modelers can represent transmission as a static system that creates practical limitations on generation siting and operations, or

[12] Detailed case studies accompanying this report provide examples of both types of planning approaches.
[13] This report does not focus on restructured markets, but readers may draw on the diverse examples provided throughout, including New York's Coordinated Grid Planning process discussed in section 3.4.2 and the Vermont case study available here, to assess similarities and differences in approaches and how they may apply.
[14] Transmission planning is performed at various levels, from a single utility to regional and interregional planning involving federal regulation and, in some areas, Regional Transmission Organizations (RTOs) or Independent System Operators (ISOs).

capacity expansion models may include transmission projects as investment candidates to help identify the optimal future transmission system design in consideration of generation needs.[15]

1.2 Methodology

Lawrence Berkeley National Laboratory used a variety of methods to identify states and utilities that are incorporating DSP elements in IRP processes, delineate common and leading practices, and describe information gaps, challenges, and tactics to achieve desired planning outcomes.

The authors identified a list of foundational contributions to the field, including academic research, industry white papers, reports, and other documents (Appendix B). A resulting annotated bibliography synthesized findings to identify common challenges and assess early examples of coordinated or integrated planning across electricity system domains. Findings informed questions for subject matter expert interviews (Appendix C) and helped identify key case studies.[16]

Researchers also reviewed relevant state regulatory requirements and utility IRP and DSP filings to assess implementation of planning coordination across multiple jurisdictions, selected to capture a range of planning maturity and regulatory environments. The analysis focused on identifying:

- Formal requirements or guidance for IRP–DSP coordination (e.g., statutory language, commission orders, or regulatory rules)
- Shared analytical components between IRPs and DSPs, including load forecasting, scenario development, GER valuation, and need assessments
- Evidence of feedback loops — how distribution-level insights are used to inform resource planning, and vice versa.

Research also included semi-structured interviews with representatives of utilities, PUCs, and industry organizations. Interviews gathered practitioner perspectives on the current state of IRP–DSP coordination, including organizational processes, technical integration, data sharing, and regulatory drivers or constraints. Interviews augmented literature review findings, informed case study development, and supported analysis of regulatory documents and utility filings. Leveraging all of these findings, the report provides tactics to support utilities and PUCs pursuing integration of distribution planning elements in resource planning for bulk power systems.

1.3 Utility Planning Processes

In order to understand how to better consider elements of DSP as part of IRP or other long-term planning for bulk power systems, it is helpful to have a foundational understanding of the objectives and methods of IRP and similarities, differences, and key touchpoints with DSP.

---

[15] ESIG, 2025.
[16] Case studies are available at https://eta.lbl.gov/publications/effectively-considering-distribution.

IRP has been the core mechanism for long-term decision-making by vertically integrated utilities for the bulk power system, guiding utility resource investments to meet projected system needs. The typical planning horizon is 10 to 20 years. In some jurisdictions, it is longer.[17]

DSP typically addresses reliability and capacity expansion needs for the local delivery grid. Planning encompasses immediate operational needs, short-term action planning, near-term asset investment decisions, and longer-term capital planning up to 10 years into the future (Figure 1).

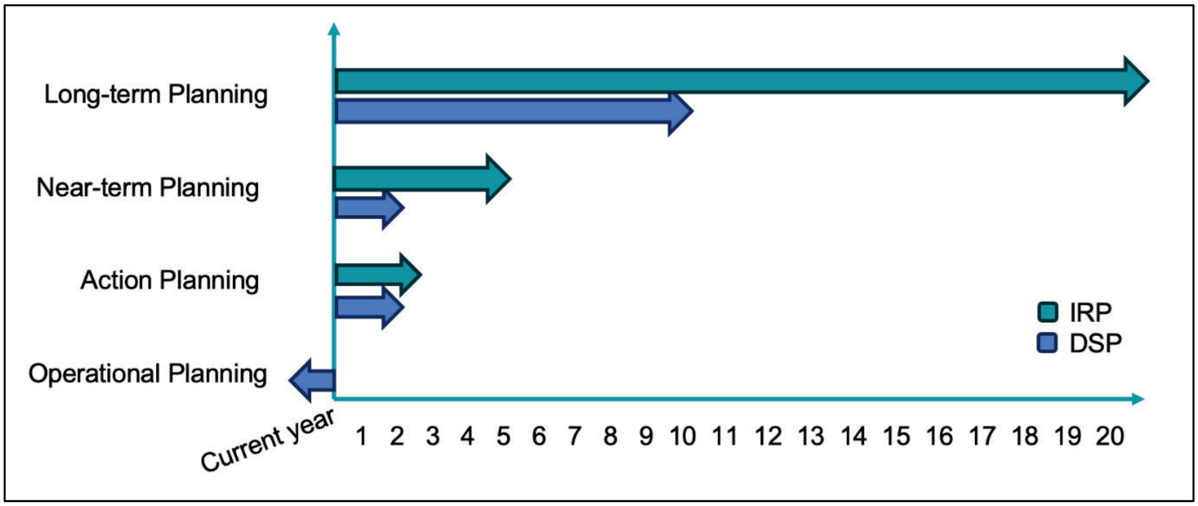


Figure 1. IRP and DSP Planning Horizons (Sources: Adapted and expanded from U.S. DOE, 2020, and Biewald et al., 2024)

These planning processes have historically operated in isolation given the significant differences in how the BPS and distribution systems function. The BPS is electrically connected to the distribution system at substations, where electricity is stepped down in voltage by transformers and delivered to customer premises via distribution system equipment. This interface was originally designed only for one-way power flows, from utility-scale generation to customers, but increasingly experiences bi-directional flows from generation and storage connected to distribution systems. Growth of such GERs, new and rapidly growing customer loads, and technological advancements have created an increasingly two-way and dynamic grid wherein distribution-level insights about load growth, distribution system hosting capacity[18] for loads and local generation, and grid reliability inform long-term bulk resource choices. Conversely, decisions made at the bulk system level can affect distribution system operations and investments. These trends have blurred the lines between planning domains and led PUCs and utilities to pursue coordinated planning approaches.[19]

[17] Biewald et al., 2024.
[18] Hosting capacity determines the amount of load or GERs that can interconnect at a specific point on the grid without infrastructure upgrades or adversely impacting power quality or reliability under existing control and protection systems.
[19] ESIG, 2025.

Some jurisdictions and utilities are going beyond coordination by pursuing ISP. While ISP is still relatively uncommon, its emergence reflects a recognition that siloed planning processes are not the best way to address emerging energy system challenges.[20]

1.3.1 IRP Overview

IRP identifies least-cost, least-risk portfolios of resources to meet projected bulk system needs. The objective is to evaluate plausible futures for the utility system, identify portfolios that can meet demand reliably and affordably, and provide PUCs and stakeholders with transparent information on costs, risks, and trade-offs.[21] Today, most regulated utilities are required to file IRPs regularly with state commissions, typically every 3–5 years (Figure 2).[22] IRP employs a variety of analyses and a suite of modeling tools (Figure 3).

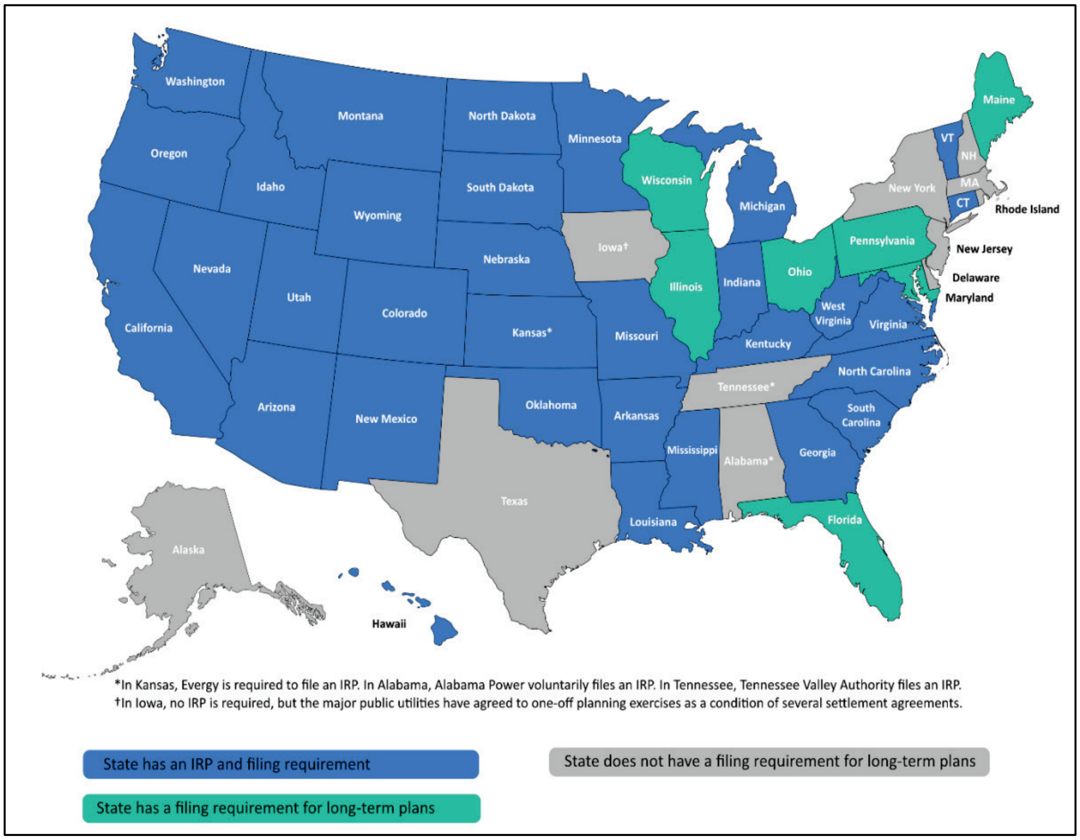


Figure 2. States with Integrated Resource Planning or Similar Processes (as of November 2024) (Biewald et al. 2024)[23]

[20] Burdick et al., 2024.
[21] Biewald et al., 2024.
[22] Ibid.
[23] Alaska recently adopted a multi-utility IRP requirement. New York requires a Coordinated Grid Planning Process that could be considered a form of bulk system planning.

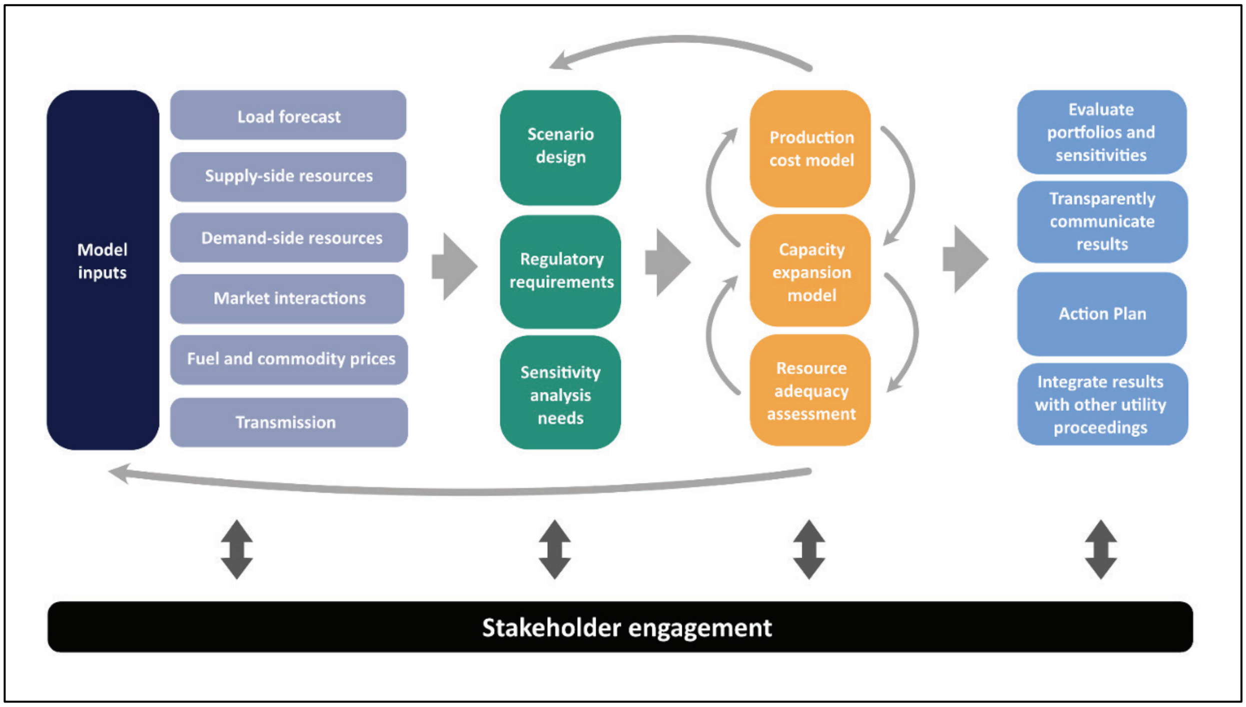


Figure 3. Typical IRP Process (Biewald et al., 2024)

IRP analyses typically include the following processes.

- **Load forecasting:** Load forecasting is the foundation for IRP, serving as an input to production cost, capacity expansion, and resource adequacy assessments. IRP load forecasts are typically done at the zonal level (aggregated to system level), and assess peak demand and energy use by customer segment (e.g., residential, commercial, industrial). Leading practices include forecasting locational GER adoption, hourly GER and load flexibility shapes, and planning for large load growth such as data centers (also called "spot loads").[24]
- **Capacity expansion modeling:** Portfolio optimization models that minimize system costs (capital, fixed and variable operations and maintenance [O&M], fuel) to meet future needs. They determine optimal portfolios of utility-scale generation, storage, and sometimes selected GERs and transmission. These models usually develop portfolios for a 10-20 year period (and in some cases, a longer timeframe), with snapshots of representative intervals or full annual chronological runs. Outputs include investment and retirement decisions, long-term resource mixes, cost projections, and other metrics aligned with planning objectives.[25]
- **Production cost modeling:** Also known as unit commitment and economic dispatch, production cost models simulate chronological system operations at hourly or sub-hourly intervals. They optimize resource (generation and storage) dispatch, unit commitment, and ancillary service provision, minimizing system costs (fuel, O&M,

[24] Biewald et al., 2024.
[25] ESIG, 2025.

startup/shutdown) to meet demand. Outputs include dispatch schedules, locational marginal prices, production and operating costs, congestion patterns, and system operational performance metrics. Together, capacity expansion and production cost models provide cost and unit commitment information for planners to align investment strategies with future operations.

- **Resource adequacy assessment models:** These probabilistic models evaluate the likelihood that the system can balance supply and demand and produce modeling runs across a wide range of weather and operational conditions. This results in thousands of years of simulated operations to calculate resource adequacy metrics, typically using capacity expansion model portfolios as inputs. Outputs include loss-of-load expectation, expected unserved energy, loss-of-load hours, and characterizations of resource adequacy risk periods.
- **Risk and sensitivity analyses:** These analyses stress-test portfolio robustness across uncertain futures such as load growth rates, fuel prices, weather-driven variability, GER adoption, and potential changes in regulations. Outputs include ranges of system costs, identification of common investments across scenarios (least-regret actions), and reliability outcomes.[26]

IRP filings typically include a preferred resource portfolio and alternative portfolios, along with associated cost, reliability projections, and other metrics. Many jurisdictions require an action plan, which translates the long-term resource strategy into concrete near-term steps such as procurement schedules, specific requests for proposals, and program designs.[27,28]

Bulk Power Resource Procurement

Procurement translates the utility's preferred IRP portfolio into actual investments. The IRP informs the general type, quantity, and timing of resources needed, while procurement decisions typically occur separately and follow their own requirements. However, explicit alignment between planning and procurement contributes to solicitations that are directly tied to validated IRP assumptions and system needs (Biewald et al., 2024).

Procurement can be a key bridge between IRP and DSP, because it is the mechanism through which utilities acquire solutions capable of meeting electricity system needs at the bulk power or distribution system level (Kahrl and Schwartz, 2021).

1.3.2 IRP and DSP Similarities and Differences

IRPs emerged in the late 1970s and 1980s.[29] DSP filing requirements began far more recently, starting in 2013.[30] While adoption is growing rapidly, fewer states require regulated utilities to file DSPs compared to IRPs.

26 Ibid.
27 Ibid.
28 Wilson and Biewald, 2013.
29 Kahrl et al., 2016.
30 Homer et al., 2017.

Historically, distribution planning focused narrowly on forecasting demand growth and identifying upgrades for grid assets such as feeders, service transformers, and substations to maintain reliability. Today, however, DSP has expanded in many jurisdictions into a more complex, transparent, and participatory process that may address grid modernization (e.g., a technology enablement roadmap), resilience, and coordination with bulk system planning or other planning processes.[31]

Still, distribution planning varies in scope, sophistication, and name across the country. For example, Transmission and Distribution (T&D) Improvement Plans are a type of DSP focused narrowly on near-term investments to meet reliability needs, with expedited cost recovery for approved elements. On the other end of the spectrum, integrated distribution planning uses a systematic approach to satisfy customer service expectations and state and utility objectives for grid reliability, resilience, safety, operational efficiency, and GER integration and utilization. Appendix A provides additional details on current DSP practices. Twenty-two states, Puerto Rico, and the District of Columbia require regulated utilities to file some type of distribution system plan (Figure 4).[32]

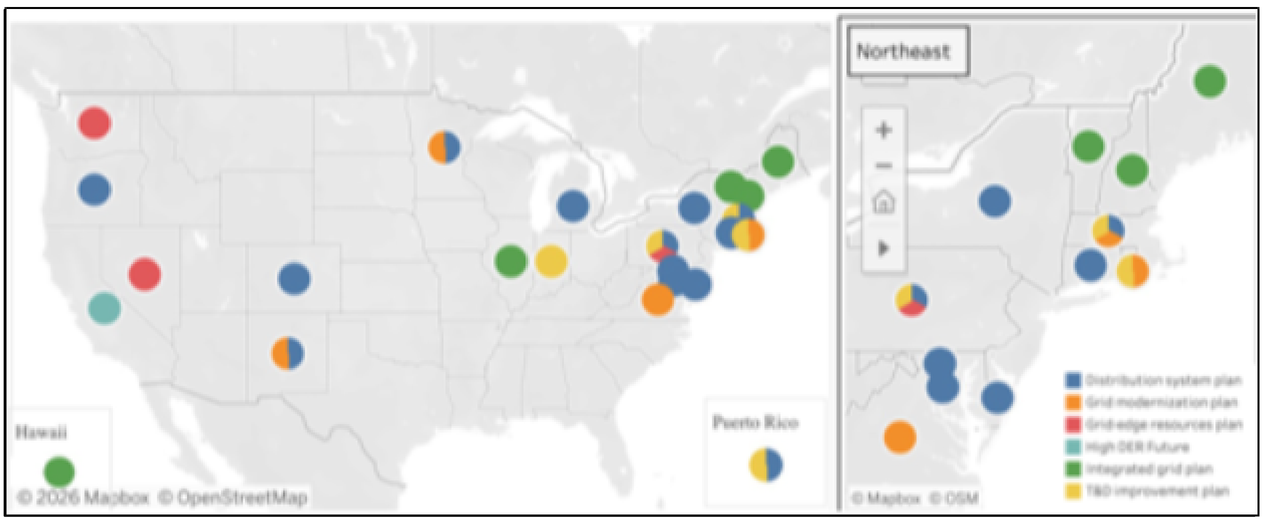


Figure 4. State DSP Planning Practices (LBNL, 2026)

Table 1 summarizes key differences between DSP and IRP. While they have steps and analyses in common, these planning processes are designed to answer different questions, and many modeling tools and methodologies differ.

[31] Schwartz et al., 2024.
[32] See LBNL's online catalog of State Electric Distribution System Planning Practices.

Table 1. Comparison of IRP and DSP Processes

Element	IRP	DSP
Question answered	What is the least-cost, least-risk mix of resources needed to meet long-term electricity demand?	What investments and other actions are necessary for the utility to design, maintain, and manage the low-voltage network to maintain deliverability and reliability?
Filing frequency	Every 3-5 years	Every 2-5 years
Planning Horizon	10-20+ years	5-10 years
Load Forecasting	Aggregated system-level (or zonal) demand by customer segment for each hour of the year	Localized, disaggregated peak loads — up to 8,760 hourly forecasts
Common Modeling Approaches	● Capacity expansion models ● Resource adequacy models ● Production cost models	● Power flow simulations ● Short-circuit / fault modeling
Typical Plan Outputs	● Load/resource balance ● Preferred resource portfolio* ● Near-term action plan ● Alternative resource portfolios ● System costs ● Resource adequacy metrics focused on long-term reliability	● Grid needs assessment ● Near-term action plan ● Long-term capital plan ● Day-to-day reliability metrics such as system average interruption duration index (SAIDI) and system average interruption frequency index (SAIFI)
Other Differences	● More commonly uses scenario analysis ● Relatively more agnostic to resource locations, subject to transmission constraints ● Formal filing requirements are common	● Scenario analysis is an emerging practice ● Focused on location-specific needs ● While formal filing requirements for regulated utilities are growing, they are less common compared to IRP

*The preferred resource plan also could be considered a long-term capital plan. IRP and DSP use different terminology for final outputs and cover different time horizons.

2. The Value Proposition for Incorporating Distribution Planning Elements in IRP

Utility distribution system investments are rising in many regions, driving rate increases (Figure 5 and Figure 6) at a time when affordability is top of mind.

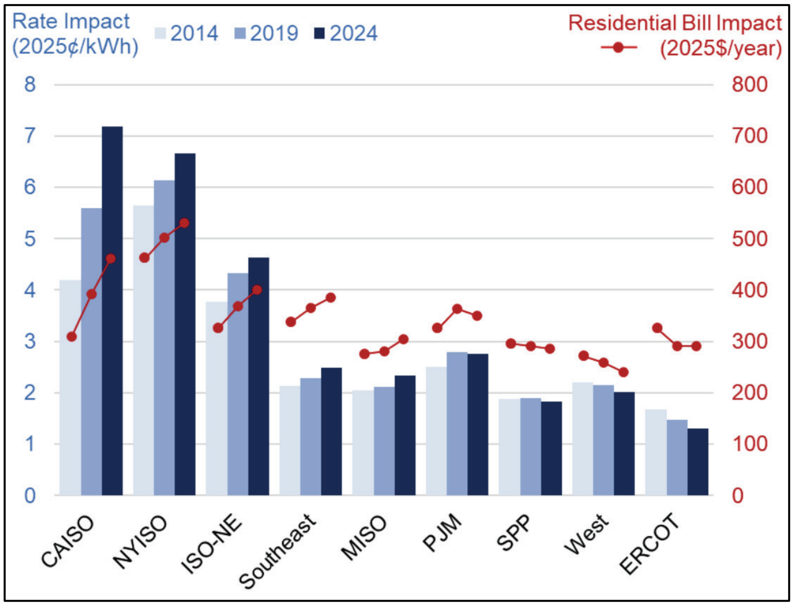


Figure 5. Approximate Rate and Bill Impacts of Distribution Costs (Wiser et al., 2026a)[33]

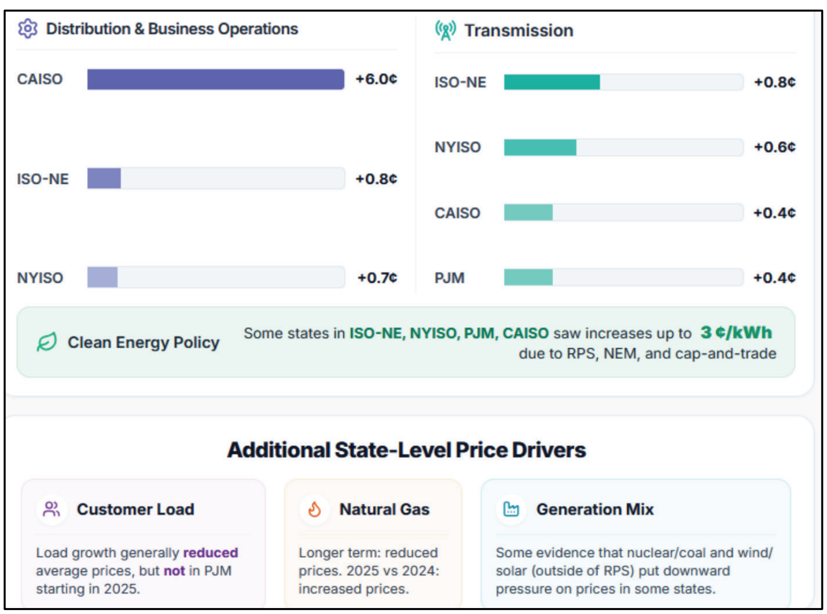


Figure 6. Primary Drivers of Inflation-Adjusted Price Increases, 2019-2025 (Wiser et al., 2026b)

[33] Values are 3-year rolling averages. Estimates are rough approximations of rate impacts. Includes distribution CapEx and infrastructure-related O&M; business operations, insurance, billing and other functions that may be allocated to “distribution” are not included.

These trends have led to a paradigm shift for DSP at some utilities and PUCs, extending beyond an engineering- and reliability-focused exercise. Interviews for this study revealed that in jurisdictions where utilities are subject to least-cost planning statutes, bulk power system planners increasingly are looking at the distribution system for potential resource solutions. In other cases, PUCs and stakeholders are driving forces, requesting greater DSP visibility.

In addition, distribution-connected resources influence the type, timing, and amount of bulk system resources needed. This increasingly requires consideration of distribution planning elements in IRP.

2.1 Benefits of Incorporating Distribution Planning Elements in IRP

Coordinating across various types of electric planning processes can create numerous benefits:[34]

- Harmonized plan results and reduced conflicts between separate plans through use of consistent inputs and methods[35]
- More accurate identification of grid needs by capturing all relevant factors that may influence the system
- Cost savings realized by reconciling forecasts to more accurately assess investment needs and all possible alternatives to meet them
- Increased understanding, transparency, and credibility of plan results
- Higher quality information provided to planners and decisions makers if stakeholder engagement is coordinated across different planning processes
- Administrative efficiencies realized by applying knowledge from multiple planning processes across workstreams.

Assessing the benefits of integration specifically between IRP and DSP processes is nascent. However, limited findings note reduced transmission losses, improved reliability and resilience, and improved deployment of GERs as non-wires alternatives (NWAs) or bulk power system resources.[36] The value of coordinated planning can be challenging to quantify. Subject matter expert interviews, detailed below, support the hypothesis that coordination leads to improved utility plans that serve customers and state and utility objectives more effectively.

2.1.1 Improved Planning Outcomes

Consideration of distribution system elements in IRP optimizes grid investments. This is the most commonly cited value proposition, identified by over half of interviewees across a variety of organization types and geographic areas. Making better use of existing infrastructure, or avoiding or reducing the need for new or upgraded equipment, reduces costs and may provide other benefits such as reduced outages to enable safe construction. For example, when considering distribution asset health, utilities may identify opportunities to create additional hosting capacity at the same time. This is the case in New York, where developers

[34] See Appendix B; Schwartz et al., 2024.
[35] Regulatory review of proposed investments can be challenging when plan results differ.
[36] Burdick et al., 2024.

may request hosting capacity additions in conjunction with planned utility construction projects.[37] In general, considering distribution-level resources and constraints allows planners to optimize the system by providing greater visibility into holistic electricity needs based on the amount, timing, and location of electricity demand and the solutions available to serve that demand and meet other grid needs.

More robust planning can help utilities build in the most effective manner. For example, IRP that spreads a load forecast across broad geographic zones somewhat evenly ("peanut butter approach") risks missing large loads that may materialize in specific areas on the sub-transmission level. Such practices also may lead to suboptimal siting and sizing of generation and associated transmission.

DSP provides a more granular picture of where new loads are expected. That can improve quantification of resource needs in constrained corridors and strategic siting of generation and storage close to loads to reduce line losses and associated costs. Such insights may help utilities meet overall electricity system needs at a lower cost than traditional upgrades or new infrastructure. Operational strategies also help realize these benefits, such as strategically flexing storage or load on the distribution system at peak times to reduce the need both for bulk power and distribution system upgrades.

Optimized planning reduces electricity system costs and improves electricity affordability. The benefits noted above have potential to reduce overall system costs by improving information on the location, amount, and timing of resources needed. In addition, greater visibility into equipment loading patterns and specific planning violations through technologies such as advanced distribution management systems and GER management systems can help planners reduce overly conservative assumptions used to maintain reliability. For example, distribution-level visibility into actual storage charging behavior may reveal that more charging occurs off-peak than the utility assumed, allowing planners to increase available load hosting capacity.

Greater system visibility also improves insight into more cost-effective locations for generator interconnection and can provide more accurate information in the utility resource procurement process (e.g., timing of resource needs and siting insights). Improved distribution system visibility also improves situational awareness for wildfire and other costly grid threats.[38]

2.1.2 Improved Transparency and Trust

Consideration of distribution system elements in IRP improves plan credibility. PUCs and participants in utility planning proceedings increasingly want to understand how planning affects utility decision making, including capital investments. Several utility interviewees noted that IRP is an important communication tool for PUCs and stakeholders. Including elements of DSP in IRP improves planning transparency and builds trust because stakeholders view the

---

[37] NY PSC, 2021.
[38] For additional information on the intersection of distribution system planning and resilience, see https://emp.lbl.gov/publications/integrating-resilience-planning.

utility's IRP as more thorough and reliable. Bulk system planners also are better able to answer stakeholder and PUC questions after analyzing distribution system trends like customer adoption of new technologies.

Coordination across plans reduces the possibility that results are in conflict and better harmonizes outcomes. When multiple plans demonstrate a grid need, the justification for investments is stronger — similar to how utilities select a preferred portfolio that includes resources the capacity expansion model selects across multiple scenarios. Showing how distribution-level investments enable better IRP outcomes further validates planned investments.

Coordinated plans provide greater insight into distribution expenditures that may drive rate increases. This can be particularly helpful for investments in distribution-level situational awareness and management infrastructure. For example, utilities invest in advanced distribution management systems (ADMS), advanced metering infrastructure (AMI), GER management systems, and other technologies to help monitor, operate, and manage the local grid, improving day-to-day reliability and resilience to severe weather and physical and cyber threats. PUCs are more likely to support these types of investments when applications include clear linkages with state priorities and electricity planning processes, strong cost-effectiveness and alternatives analysis, and clear prioritization of potential investments.[39] Demonstrating how investments create value for both the distribution and bulk power systems can help meet these criteria. For example, Hawaiian Electric's Integrated Grid Plan discusses how planned investments in grid modernization technologies such as ADMS are critical to managing a portfolio of resources where GERs contribute meaningfully to system needs.[40]

Coordinated planning reduces utility functional silos. Interviewees emphasized the value of conversations across planning teams to share learnings, elevate the importance of DSP across the utility, and begin to standardize integrated planning techniques into business-as-usual practices. Planners build their expertise and capabilities by collaborating with one another, working through challenges, practicing new techniques, and improving processes over time. Placing all planning functions under a single business unit within the utility breaks down planning silos and provides decision-makers with better information that improves planning outcomes. PUCs and stakeholders also may build expertise in new areas, improving regulatory review of utility investment decisions.[41]

2.2 Challenges to Incorporating Distribution Planning Elements in IRP

The literature consistently points to three types of challenges associated with integrating across two or more types of electric system plans:

---

[39] Schwartz and Mims Frick, 2024; For additional information on regulatory treatment of grid modernization investments, see Mims Frick, Schwartz, and Sandonato, 2025.
[40] Hawaiian Electric, 2023.
[41] For example, in 2021, certain PUC participants in the NARUC-NASEO Comprehensive Electricity Planning Task Force committed to actions to advance integrated planning. Many of these states continue to pursue emerging planning techniques (NARUC, 2021c).

- Institutional silos within utilities and PUCs between resource, transmission, and distribution planning functions
- Data gaps, analytical limitations, and increased modeling complexity to accommodate granular distribution system inputs in typically systemwide IRP analysis
    - For example, incorporating forecasts for customer storage adoption with sufficient spatial and temporal granularity and conducting sufficiently detailed analyses to accurately identify and evaluate potentially less costly alternatives for both distribution and bulk power system services
- Addressing uncertainties stemming from rapid changes in technologies, load profiles, and large loads, including higher risks of stranded assets

The following interview findings corroborate these issues and illuminate additional challenges and limitations specifically related to including distribution system elements in IRP.

2.2.1 Analytical Challenges

Data marshalling is resource-intensive. Distribution-level sensors, communications equipment, and AMI produce vast amounts of data that can improve IRP forecasts and other key planning inputs. But reaping these benefits requires investment and experienced staff to set up data sharing systems, clean up data, translate locationally- and temporally- granular data for use in less granular IRP analyses, and keep data up to date in a useful format.

Modeling capabilities remain a genuine constraint. Interviewees agreed that, in practice, no single model can fully co-optimize grid investment decisions across bulk, distribution, and customer levels. This is in part because the transmission and distribution systems differ fundamentally in the physics being solved (balanced positive-sequence transmission power flow versus unbalanced three-phase distribution power flow), in temporal resolution requirements, and in scale. For example, a distribution system can have an order-of-magnitude more nodes than the upstream transmission model. Even where such linked models exist, computing power remains a binding constraint on their practical use. Data assembly and reconciliation are also often key limiting factors in the quality of distribution planning, with utility planning processes lagging behind both the granularity of available system data and the pace at which new electricity technologies are being deployed in the field.

However, a growing need for analysis that spans traditional simulation boundaries, such as evaluating the impact of distribution-level resources on bulk-power system operation, is driving software developers to make strides. Most notably, co-simulation platforms link separately developed transmission, distribution, which allows simulators to exchange information at runtime to create larger, more complex composite models.

IRP and DSP are designed to answer different questions. IRP addresses systemwide energy and capacity needs, whereas DSP addresses granular locational needs for the local grid. Thus, IRP inherently addresses larger-scale investments, diluting the importance of incorporating distribution system considerations in some cases. For example, planning reserve margins used in IRP subsume variability in local loads and generation. To illustrate, when utilities plan for a data center on the bulk power system, the effort needed to consider aggregated distribution system assets in IRP to meet that need may outweigh the potential value because such assets are unlikely to meet the large resource capacity levels needed.[42]

For these reasons, utilities, PUCs, and stakeholders can consider which DSP elements will have the most meaningful impact on IRP outcomes — as identified in this report — and focus integration efforts in those areas. Among these are growing loads that may change the relative economics of bulk vs. local resource options.[43]

2.2.2 Procedural Challenges

Cross-functional expertise and organizational structures are limited. There are often workarounds for technical challenges, but they require skilled experts with sufficient time and support. It is uncommon for utility planners to have expertise in both bulk power system and distribution system planning. An additional challenge generally is attracting talented utility engineers and planners. These challenges are exacerbated by utility organizational structures that divide planners by system level, with different directors, and the absence of top-down emphasis on planning coordination and skills development. Building expertise across electricity domains requires change management, time, and a willingness to overcome inertia built through many years of working on a single type of planning. Having explicit direction for coordinated planning from utility executive leadership or the utility regulator can help facilitate required business reorganization.

Assessing impacts of planning coordination is challenging. As an emerging area, there are no standard practices for assessing the consistency of results across IRP and DSP. It requires thoughtful analysis by utilities, PUCs, and stakeholders to identify areas of overlap or discrepancies, particularly when plans are filed at different times and when results are applied in a different type of proceeding such as a rate case. There also are no standard outcome-based metrics to quantify the impacts of incorporating distribution planning elements in IRP. In the future, such metrics will align with core desired planning outcomes – reliability and cost. Utilities can begin assessing coordination impacts using metrics developed with PUCs and stakeholders, such as improvements in reliability[44] per dollar invested in both the bulk power and distribution systems, and overall plan costs for scenarios that do and do not consider distribution level-connected resources.

Integrated planning proceedings are more complex. Proceedings covering both bulk and distribution system processes in-depth can be lengthy. The resulting plans may not be as timely as would be ideal, which can reduce their usefulness. It is helpful to recognize when to move

[42] However, co-location of generation and storage at data centers is an important resource strategy, regardless of whether the large load is connected to the bulk power or distribution system.
[43] Not all utilities have the load growth — or the type of load growth — that supports that value proposition.
[44] Using metrics such as System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), Customer Average Interruption Duration Index (CAIDI), and Customer Average Interruption Frequency Index (CAIFI).

through things more quickly and not get bogged down in process or analysis, particularly to support effective stakeholder review and understanding.[45]

As states and utilities advance planning capabilities, it is critical to consider the objectives for IRP and DSP, utility context (e.g., types of customers and loads, customer adoption levels of distributed generation and storage, rural vs. urban service areas), the types of processes where value is most likely to be gained from coordination, and tracking successes and lessons learned.

[45] Some experts expressed that spending too much time trying to get every detail associated with IRP analyses exactly right, including highly granular distribution-level inputs and assumptions, may not be necessary when there is a high level of uncertainty around planning for the long-term future.

3. Methods for Incorporating Distribution Planning Elements in IRP

Tactics for incorporating distribution system elements in IRP include administrative and process-oriented practices and analytical coordination practices. Past research provides foundational information on general strategies for coordinating electricity system planning.[46] This study builds on that work by identifying how those strategies apply within specific IRP and DSP processes and by detailing key analytical linkages.

Methods range from light-touch and less complex activities, such as referencing information across proceedings, to analytically sophisticated and resource-intensive methods such as modeling that iterates on findings across electricity system levels.[47] [48] This chapter presents activities along the spectrum to support states and utilities regardless of experience with coordinated planning to date.

3.1 Administrative and Process-Oriented Coordination

Establishing supportive administrative processes is foundational to conducting more complex analyses and coordinated modeling. Without effective management and protocols, the breadth of topics covered can become unruly. Literature and interview findings confirm the importance of these efforts and indicate that relatively simple approaches can help mitigate challenges.

Table 2 describes key tactics for supporting utility personnel and stakeholders in integrated planning processes. Most procedural aspects of coordination involve simple or moderately complex methods that require thoughtful input from project managers. These relatively low-hanging fruits support improved integration of modeling and analysis. For example, PUCs can consider aligning filing cycles so utilities incorporate updated information consistently across planning processes. PUCs in Minnesota and Michigan adjusted filing schedules to encourage synchronized or dovetailed processes.[49]

---

[46] See, for example, Schwartz et al., 2024 (Chapter 13); ESIG, 2025; De Martini et al., 2022.
[47] Schwartz et al., 2024.
[48] ESIG (2025) describes this spectrum of activities using a “walk-jog-run” framework.
[49] Terwilliger, Northagen, and Dornfeld, 2024.

Table 2. Workforce and Engagement Tactics for Incorporating Distribution Planning Elements in IRP

Tactic	Description	Impact	Level of complexity to implement
Conduct change management to reduce utility staffing silos	• Restructure utility departments so that resource and distribution planners report to the same executive • Support planners in trying new techniques by emphasizing the importance of coordinated planning, providing training and resources (e.g., models), and offering support as challenges arise	• Planners all work toward the same outcomes • Utility executives have better visibility into planning at different levels of the system • Discussion facilitates resolution of discrepancies in assumptions or approaches across planning processes	**Moderate** - This tactic requires utility executive buy-in and commitment to change
Use advisory groups strategically and effectively to engage stakeholders	• Establish advisory group and stakeholder engagement processes with a clear calendar of events • Create streamlined, consistent, and meaningful opportunities for input	• Advisory groups and stakeholders help to vet issues, maintain focus on important topics, and bring new ideas to the table • Regular, candid discussions help avoid the potential for serious planning flaws late in the process	**Moderate** - Simple steps such as clear naming conventions, maintaining public webpages, and clearly stating stakeholder roles are impactful; however, stakeholder engagement is time-intensive and stakeholder needs and ability to contribute vary
Create opportunities to build skills and expertise across stakeholders	• Improve expertise at the nexus of bulk power and distribution systems across utilities, PUCs, utility consumer offices, and other entities through educational sessions and training	• Improved skills and expertise enable proceedings to progress faster by avoiding too much time spent on foundational information or irrelevant topics • Depth of analysis, review, and feedback on utility plans also improve	**Low** - PUCs and utilities can offer educational sessions on integrated planning topics at advisory group meetings; utility engineers can attend trainings and engage with industry peers

Table 3 identifies strategies for managing information systems and proceeding workflows to support integrated planning.

Table 3. Process Management Tactics for Incorporating Distribution Planning Elements in IRP

Tactic	Description	Impact	Level of complexity to implement
Establish robust data management systems and data-sharing provisions	• Marshall data from both IRP and DSP to allow all utility planners easy access to up-to-date and appropriately formatted information that acts as a single source of information • Establish appropriate information sharing protocols for external stakeholders and provide regular updates	• Aligning inputs and assumptions across proceedings or levels of the system reduces conflicts in planning results and outcomes • Using distribution-level data, such as real-time equipment loading, in IRP can improve system utilization and enable less conservative assumptions, reducing utility costs • Data sharing improves transparency and supports better stakeholder engagement	**Moderate to High** - Simple tasks such as providing clear data descriptions, regular updates, and communication about data availability are important; however, converting large quantities of data to useful formats and translating data sets designed for use in a different proceeding is challenging
Manage proceeding calendars to effectively exchange information	• Identify key touchpoints between proceedings and sync milestones so that inputs are available when needed • When it is not possible to align timing, use consistent methodologies to develop data sets and analyses to produce cohesive, if not the same, results • Keep processes separate where appropriate to ensure sufficient depth of analysis and expertise and avoid additional work where not needed • Conduct planning in bite-sized pieces to support forward progress	• Creates meaningful integration by making outputs from distribution planning (e.g., load and storage forecasts, near-term distribution capital investments) available for the IRP process	**Moderate** - Thoughtful calendar management is theoretically simple, but is often challenged by the reality of proceeding delays and changing priorities; depending on the number of regulated utilities, types of proceedings, and complexity, it can be difficult to change existing schedules — both for utility workplans and commission proceedings
Strategically invest in new modeling capabilities	• Identify tradeoffs between costs and benefits for investing in new modeling capabilities, given that no single model currently exists to effectively analyze the full electricity system and thoughtful scenario and trade-off analysis may be sufficient	• Starting with thoughtful approaches and open source models, rather than immediately investing in sophisticated models, allows planners to develop deeper understanding of the process and identify the most pressing modeling and technological needs • Gradual investment also spreads costs for integrated planning over time	**Low** - Use existing models and capabilities and build from that foundation with more sophisticated practices and eventually new models

3.2 Analytical Coordination

At a high-level, DSP can primarily inform IRP through granular load and GER forecasting, planning for the same plausible futures (scenarios), assessing capabilities of distribution-level resources to meet bulk power system needs as well as the incremental value of these resources for local grids, and co-optimizing resources across all levels of the electricity system (e.g., through operation of distribution-connected batteries). In turn, IRP portfolios can identify the quantity and role of distribution-connected resources to help meet bulk power system needs. At a practical level, this breaks down into the following most impactful analytical linkages between IRP and DSP and associated methods for maximizing each connection point.

1. Load and GER forecasting
    - Sequenced planning cycles
    - Aligning IRP and DSP forecasting
2. Scenario planning and sensitivity analysis
3. Distribution grid optimization (i.e., improving distribution load factor and GER utilization and integration)
    - Distribution grid load factor optimization
    - Integration of GER, including:
        - Hosting capacity analysis (HCA)
        - Streamlined interconnection procedures
        - Flexible connection options
        - GER deliverability reviews[50]
4. Integrated system analysis
    - Convergent and divergent value analysis
    - Co-optimizing bulk and distribution-connected resources
    - Coordinated procurement processes

3.2.1 Load and GER Forecasting

Aligning distribution-level forecasts with system-level forecasts for IRP is important to avoid mismatches in inputs and assumptions and results of the analyses. For example, an IRP might assume one trajectory for load growth or adoption of customer-sited generation and storage, while distribution plans assume another — resulting in inconsistent investment signals, inefficient infrastructure deployment, missed NWA opportunities, and potential reliability risks across both the bulk power and distribution systems. Subject matter experts interviewed for this study emphasized forecasting as a key touchpoint between IRP and DSP. In particular, they noted the importance of understanding load variability and coincidence factors — whether timing of peak demand at the local and bulk power levels is aligned or mismatched.

Alignment of system-level (IRP) and distribution-level forecasts is essential to plan all parts of the grid to the same set of plausible future conditions. Using aligned forecasts provides utilities, PUCs, and stakeholders with a coherent, end-to-end picture of future needs to enable:

[50] Electric utility review of GER aggregations proposed to provide bulk system services for capability, safety, and reliability impacts on the local distribution system.

- Consistent decision-making across bulk power and distribution systems
- Avoidance or reduction of stranded costs from overbuilding
- Identification of least-regrets solutions that benefit both the bulk power system and local distribution grids

However, DSP and IRP forecasting differ in scope, resolution, and the types of information used to develop forecasts. Distribution planning generally focuses on local infrastructure conditions over a five- to 10-year horizon, emphasizing feeder- and substation-level impacts from known customer growth and local planner knowledge. In contrast, IRPs typically evaluate system-wide load and resource needs over a 10–20+ year horizon using more aggregated economic, demographic, and policy-driven assumptions. IRPs commonly incorporate GER impacts in aggregate form at the system level. Representation of GER adoption at a localized geographic level for the distribution system is an emerging area that requires more granular propensity models for customer adoption, hosting capacity information, and circuit-level behavioral assumptions. As a result, some utilities either exclude GER impacts from local forecasts or allocate system-level GER forecasts uniformly across distribution areas without modeling localized adoption dynamics ("peanut butter" approach).

Different DSP and IRP forecasts are not necessarily problematic if they reflect distinct planning needs or risk-management approaches. Transparency for assumptions, methodologies, and uncertainty analyses is needed so that utility planners and PUCs understand why differences exist and can incorporate the best available information into decision-making.

Table 4 summarizes key differences between system- or zonal-level (IRP) and distribution-level (DSP) forecasts.

Table 4. Differences in IRP and DSP Forecasting Techniques

Aspect	IRP	DSP-Level Forecast
Geographic Scope	Zonal representations, typically aggregated to the system level	Specific substations and feeders in a utility's network
Forecast Horizon	Medium-to-long term — 10–20+ years	Near-to-medium term — often 5–10 years
Spatial and Temporal Granularity	System-level peak demand and energy use — zonal if broken down by region; hourly simulations for entire system	Highly granular (e.g., circuit-level peak loads, hourly profiles)
GER Treatment	Aggregate GER impacts may be netted out of load forecast (e.g., onsite generation reduces residential energy consumption), or GERs may be modeled as resources (but with less locational detail than in DSP)	Explicitly models GER adoption;* GERs affect feeder loads or may serve as NWAs

Aspect	IRP	DSP-Level Forecast
Forecast Method	Uses econometric and end-use models for total load across the utility system; uses scenarios and sensitivities to reflect plausible future loads and GER adoption dependent on a variety of factors	Often relies on known customer growth, interconnection requests, and local business-development information; some utilities supplement these approaches with adoption models, spatial analytics, or advanced forecasting techniques if data are available
Addressing Uncertainty	Focuses on macro-level uncertainties — e.g., economic growth, fuel prices, and federal policy changes; scenarios have less spatial detail	Low consideration of uncertainty; less commonly, utilities may use multiple GER adoption scenarios to analyze uncertainty

* Leading practices use 8,760 hourly modeling and GER adoption propensity models (LBNL, 2026), but DSP more commonly allocates a generalized GER adoption forecast uniformly across the utility's service territory.

Leading practices for aligning IRP and distribution forecasts include (1) synchronizing planning cycles; (2) aligning forecasting for IRP and DSP — for example, by using common datasets, disaggregating IRP forecasts, and ensuring that growth of distributed storage assumed in the IRP aligns with expected adoption of this technology across all distribution feeders; and using scenario analysis to assess uncertainties.

Synchronized planning cycles – Timing gaps between IRP and DSP can under-represent fast-moving trends, such as technology adoption or new technological capabilities.[51] While utilities conduct distribution planning internally each year, they typically file updated distribution plans with PUCs (where required) every two to three years — sometimes with narrower annual updates. IRPs typically follow three- to five-year cycles. Utilities may file interim IRP updates focused on changes that have a significant impact on plan outcomes.[52]

Bridging the timing gaps between forecasts used by these planning processes can include using DSP analysis comparing recent GER forecasts to actual operational impacts of GERs. Utilities also may consider phased distribution upgrades that help bridge the gap between nearer-term DSP needs and longer-term IRP needs and manage the uncertainties associated with needs that are farther down the road.[53]

Integrating IRP and DSP Forecasting – The primary methods for aligning IRP forecasts with distribution-level forecasts are to use consistent data sets and assumptions for load and GER

[51] In some cases, GER adoption may be more fully represented in system-level forecasts than in local distribution forecasts. Utilities may apply more conservative assumptions at the feeder level to manage uncertainty in where and when impacts will materialize.
[52] For example, Hawaiian Electric files an annual update to its Integrated Grid Plan that discuss updated planning and modeling assumptions. Hawaii PUC, 2024.
[53] ESIG, 2026.

growth, disaggregate system-level forecasts down to the distribution system level, and aggregate granular distribution forecasts to validate consistency. Utilities can take various approaches to disaggregation, including using historical adoption trends, customer adoption propensity models, allocation methods, regression-based techniques, and machine learning approaches.[54] The approach may vary by component, such as using different allocators for different types of technologies, discussed further below.

“Known” or “spot” distribution loads like new commercial development, including those co-located with generation, impact energy deliverability analysis and related reliability considerations. Forecasters make adjustments for known distribution loads and distributed energy projects. In many cases, distribution and bulk power planners rely on the same underlying information regarding known new loads or large customer developments but apply different modeling assumptions. Distribution planners may assume the full localized peak-load impact at specific substations or feeders to ensure infrastructure reliability, whereas IRP models may smooth or diversify those impacts across the broader system, particularly when evaluating energy consumption or coincident peak demand at an aggregate level. As a result, differences between distribution and system-level forecasts may reflect legitimate differences in modeling objectives and risk treatment.

Interviewees at four utilities offered that discussion between planners and stakeholders is critical, including municipalities and state economic development agencies. Such discussions provide a more comprehensive understanding of the factors driving certain growth assumptions and help planners develop more accurate distribution-level forecasts that feed up to bulk system planners.

In short, alignment across bulk power and distribution system forecasts provides a common foundation for more cost-effective and credible planning. That is why a growing number of states and utilities are adopting requirements and methods to align system-level and distribution-level forecasts, as illustrated in the examples in the following text boxes. Continuous improvement of GER forecasts year over year also is critical. By comparing past forecasts with actual operational data and adjusting forecast methodologies accordingly, planners can avoid overly conservative or aggressive assumptions and provide more confidence that plans will result in least-cost solutions to resource needs.

[54] SCE, 2025.

Examples of Forecasting Alignment Requirements

Nevada - A 2019 Public Utilities Commission of Nevada (PUCN) order on integrating IRP and IDP planning required inclusion of a Distributed Resources Plan (DRP) as part of developing the IRP. The order included the following requirements: *"The net distribution system load and distributed resources forecast will include system, substation, and feeder level net load projections and energy and demand characteristics for all distributed resource types"* (PUCN, 2019).

Maryland - The Maryland Public Service Commission's (MD PSC) 2025 regulations regarding Electric System Planning, focused on integrated distribution planning, include the following forecasting requirements (excerpted):

"B. Considerations Feeding into Types of Projections

(2) Level of Granularity. The granularity of information in an electric system plan may vary as described in other sections of this regulation.

(a) As a near-term objective:

(i) Information shall be provided in an Electric System Plan at the substation level; and

(ii) Feeder-level information shall be provided as part of the planning process for feeders where there are identified system constraints;

[…]

D. GER Forecast. An electric system plan shall account for the following considerations for each electric system planning cycle and scenario.

(1) Electric companies shall develop separate forecasts for each relevant GER type, including energy efficiency, demand response, distributed generation, energy storage devices, VPPs and managed EV charging-discharging.

(2) Electric Companies shall develop hourly GER forecasts.

E. Load Forecast. Load forecasts shall account for the following considerations for each planning cycle and scenario as follows:

(1) Electric companies shall incorporate load impacts of current and future transportation and building electrification based on known information and assumptions; and

(2) Electric company distribution-level forecasts in aggregate shall be aligned to a reasonable extent with available electric company developed transmission-level forecasts and with PJM-developed system-level forecasts with an explanation provided in electric system plans for any differences and the associated factors, including differences in assumptions" (Code of Maryland Regulations, 2025).

California's disaggregation approach provides a detailed example on how system-level and distribution forecasts can be aligned. The state requires IOUs to translate statewide forecasts of electricity demand and GERs into distribution circuit-level projections for grid planning. The process starts with a single forecast data set provided by the California Energy Commission (CEC). The CEC develops a statewide Integrated Energy Policy Report (IEPR) demand forecast that incorporates load growth, energy use intensity improvements and usage reductions, and trends for behind-the-meter GERs.

Utilities use this forecast for IRPs, distribution plans, and resource adequacy assessments, with oversight by the California Public Utilities Commission (CPUC). The California Independent System Operator (CAISO) uses the CEC forecast for transmission planning studies. By using a single forecast dataset, with scenarios designed to address information needs for different use cases, the state ensures that the expected growth of GERs aligns with the growth reflected in system-level capacity needs. This alignment is critical because IRP portfolios (e.g., the number of new power plants required) inform CAISO's grid studies, which in turn influence distribution upgrades. For example, California utilities include CAISO-approved transmission projects that serve GER-deferrable services on publicly available portals for distribution plans to allow users to view attribute data for different grid layers at the same time.[55]

The disaggregation approach starts with the utility's baseline (existing) demand, using historical circuit data. The utility removes anomalies and normalizes the data for weather conditions, providing a foundation for projecting future usage. The utility then allocates the reference system-level forecasts among its distribution circuits. The following description draws from Southern California Edison's (SCE's) disaggregation methodology.[56]

The utility uses the IEPR forecast for load growth and GERs for its service area and allocates the forecast to circuits using econometric modeling that reflects customer sectors, historical usage, and "known load." Known load data represent high-confidence, bottom-up customer requests that are both certain and spatially defined, such as new data centers or fleet charging depots. The load forecasting methodology requires that known loads be mathematically integrated into the forecast by subtracting them from the net IEPR growth forecast for the first planning year. This ensures that the general IEPR growth projections, which are allocated spatially across distribution feeders using models such as LoadSEER, do not double-count growth the utility already accounts for as specific customer commitments.

If aggregated known loads for a given year exceed the generalized IEPR forecast for that period, the excess load amount is carried forward to subsequent years. This carry-over continues until the forecasted IEPR growth is large enough to absorb the cumulative known loads.

Because known loads represent certain, imminent customer demand, they effectively establish

[55] SCE, 2025 at A-58.
[56] See Section 4 of SCE's [2025 Grid Needs Assessment]() report for the utility's methodology for disaggregating the CEC's IEPR forecasts for GERs (SCE, 2025).

the immediate baseline demand that existing infrastructure must meet. This high level of certainty means that the aggregation of known loads at a specific substation or feeder can immediately trigger a grid need. In other words, a grid need is established if the aggregated known loads, combined with other factors, push the total forecast load above the circuit capacity limit. Known loads have also factored into the demand forecast used for resource and transmission planning.

A stakeholder engagement process with local and tribal governments enables engineers to proactively identify new loads before formal service requests, particularly for “pending loads,” which are less certain than known loads. Stakeholder engagement also facilitates assessments of the timing of service requests based on locally-provided information, the progress of development, and institutional knowledge from previous developments.[57]

GERs are more complex to assess, since they can increase or decrease net demand depending on technology and operation. As part of the California disaggregation process, SCE applies a set of tailored methods to the IEPR service area forecast for each major GER category (see text box).[58]

Key assumptions in these forecasts include proportional scaling of adoption, geographic mapping from ZIP codes to circuits, and accuracy of hourly load and GER shapes. Expert review and stakeholder engagement inform the methodology.

After combining load and GER forecasts, the utility calculates net demand for each circuit and substation at hourly resolution. Known projects are layered in. Before declaring capacity shortfalls, planners test whether load can be shifted to neighboring circuits to avoid system upgrades. The final forecasts are stress-tested under various weather conditions, such as a one-in-ten hot year, to ensure grid reliability under extreme scenarios.

In 2024, the CPUC provided guidance to utilities on ways in which DSP forecasts can deviate from the IEPR methodology, recognizing that DSP forecasts require greater temporal and locational granularity than forecasts for IRP. The change allows certain deviations from the IEPR forecasts to better integrate reliable, bottom-up data into DSP, which may mitigate any loss of granularity (e.g., diversified load shapes) associated with disaggregating a system-level forecast. The Commission required the utilities to work with both the CEC and CPUC to “develop proposals for the method and accounting for discrepancies between the system and circuit level.”[59]

---

[57] CPUC, 2024a.
[58] Additional information on SCE’s forecasting process is included in the detailed case studies, available at https://eta.lbl.gov/publications/effectively-considering-distribution.
[59] CPUC, 2024a.

Methods for Disaggregating System-Level Forecasts – Southern California Edison

- **Energy Efficiency:** Savings estimates are assigned at the circuit-level in proportion to each circuit's existing consumption by customer sector. Hourly profiles from the system-level forecast shape how efficiency reduces demand at different times of day.
- **Electric Vehicles (EVs):** For light-duty vehicles, the utility applies ZIP code-level adoption models that factor in demographics, income, and historical registrations, then maps them to circuits. SCE uses proprietary tools for medium- and heavy-duty vehicle modeling, which forecasts truck electrification by location and charging pattern. Hourly charging shapes are applied to reflect usage profiles for charging.
- **Solar Photovoltaics (PV):** Growth estimates are divided between new construction—allocated using housing starts and building permit data—and existing home or business adoption, modeled using an S-curve diffusion approach at the ZIP code level. Non-residential PV is statistically allocated using historical adoption trends, customer characteristics (e.g., load profile/size), and hosting capacity to determine the distribution system's locational potential.* Hourly generation is modeled with "dependability" shapes adjusted for cloud cover and other degradation factors.
- **Battery Electric Energy Storage:** Residential battery storage is assumed to co-locate with PV, and estimates are allocated based on PV shares at the circuit level.** Nonresidential storage is assigned to customers with high peak-to-energy ratios, since they benefit most from peak reduction. Hourly storage charge and discharge profiles are scaled to circuit allocations.
- **Fuel changes:** Increases in electric demand from changing end-uses (e.g., switching between gas and electricity for space or water heating) are allocated by sector and shaped using system-level hourly profiles (SCE, 2025).

* Existing hosting capacity may not be appropriate to use for this method if, as is being pursued in several states, alternative interconnection cost allocation methods are employed to reduce economic barriers. For example, several state regulations, including Massachusetts (D.P.U. 20-75-B) and Maryland (COMAR 20.50.09.06(R)), allocate upgrade costs among the interconnecting entities that will benefit from the upgrades immediately and in the future.

** This assumption may under-estimate battery adoption because customers purchase standalone batteries for reliability and resilience. A recent study found that outages caused a 45 percent increase in battery adoption that would not have otherwise occurred. Brown and Muehlenbachs, 2023.

3.2.2 Scenario Planning and Sensitivity Analysis

A *scenario* is "a model run with a specific set of input assumptions and constraints—internal and external—to provide insights on distinct questions. Often, scenarios represent different goals or views of the future."[60] By developing multiple, contrasting scenarios, the utility can better understand uncertainties associated with forecasts and assumptions, test strategies, and prepare for a wide range of outcomes. The process begins by identifying the most important uncertainties about future conditions. Planners then develop a set of scenarios that reflect

[60] Biewald et al., 2024, at 51.

different ways these uncertainties might unfold. Leading practice is to use a common set of scenarios across both IRP and DSP and reconcile any conflicting outcomes.

A *sensitivity* is a model run that changes a single key input (e.g., gas prices or technology costs) to understand how that input affects or drives results, often across multiple scenarios.[61] Leading practices emphasize aligning key assumptions (e.g., load growth, GER adoption, fuel price changes) to ensure that resource and distribution plans are built on consistent futures. The examples below highlight emerging state trends.

Examples of Scenario Alignment Across IRP and DSP

Nevada - Nevada Senate Bill 146 (2017) required integrated resource plans, which incorporate distributed resource plans, to include "*A comparison of a diverse set of scenarios of the best combination of sources of supply to meet the demands or the best methods to reduce the demands...*" (SB 146). This requirement was reflected in the Nevada PUC 2019 IRP order (NV PUC, 2019).

Washington - Utility IRPs, which may include GER plans, must include "*a range of possible future scenarios and input sensitivities for the purpose of testing the robustness of the utility's resource portfolio under various parameters*" (WAC, Title 480, Chapter 480-100, Section 480-100-620). Utilities use these scenarios and sensitivities to "*assess the effect of distributed energy resources on the utility's load and operations,*" including identifying any "*need to develop new, or expand or upgrade existing, bulk transmission and distribution facilities.*" The requirements include describing scenarios and sensitivities, including those informed by an advisory group process.

California – Utilities following California's Distribution Planning Proce each may select a system-level scenario developed by the CEC in its IEPR for use in distribution planning, as discussed above (CPUC, 2024b).

Other states - Maryland, the District of Columbia, and Minnesota are updating planning guidelines to require a common set of scenarios between bulk power planning processes and DSP.

3.3 Distribution Grid Optimization

Distribution capacity planning has become a critical foundation for more integrated electricity system planning as utilities balance growing loads with the rapid adoption of GERs. Beyond ensuring reliability during peak demand, today's planning also accounts for evolving load patterns and energy exports from distribution generation co-located with loads. Utilities are

[61] Ibid.

making advancements in distribution planning to better assess grid needs, optimize existing assets, and interconnect new loads and distribution-level generation for system reliability and customer affordability.

3.3.1 Distribution Grid Load Factor Optimization

Electric distribution feeders in the U.S. on average operate well below their peak capacity. Most U.S. distribution systems have an asset utilization of about 30–35%.[62] This means that most feeders are carrying only about one-third of their maximum demand capacity most of the time. This has a direct impact on the availability of hosting capacity and the need for capacity upgrades to address load growth. This low utilization also affects the number of distribution capacity upgrades that may be needed, as increasing utilization can reduce available capacity.

Low utilization is primarily due to two compounding factors:

- Residential and small commercial customers represent over 90% of all distribution customers on average and have low average load factors.[63,64]
- Distribution contingency planning criteria typically involves reserving a portion of distribution capacity for emergency switching.

Residential loads typically have a 25-40% load factor due to demand spikes during morning and evening hours, with load dropping off overnight.[65] The result is pronounced daily peaks with much lower consumption during off-peak hours, leaving the feeder's capacity underutilized for a large portion of the day. Likewise, mixed-use feeders serving small commercial customers (such as offices, retail, or mixed residential-commercial areas) typically have load factors in the 40–60% range. Commercial loads tend to be more constant during standard workday/operating hours due to lighting and space conditioning.[66] Figure 7 shows typical feeder loading in Duke Energy's system, which is predominantly residential load at the peak hour.

---

[62] Steyer, 2025.
[63] Load factor is the ratio of average load (actual energy used) to peak load (maximum demand) over a period, typically expressed as a percentage. A 33% load factor, for instance, means the feeder's average demand is one-third of its peak demand for that period. Higher load factors denote more even, efficient use of grid capacity, whereas low load factors signify sharp peaks with long periods of low utilization.
[64] There are approximately 166 million electricity customers in the U.S. — about 145 million residential, 20 million commercial, and 1 million industrial customers, according to FindEnergy.
[65] The Electricity Forum, 2025.
[66] In contrast, industrial customers, typically served by transmission or sub-transmission systems, may have very high load factors. These load factors are often greater than 70% because many industrial operations run almost continuously.

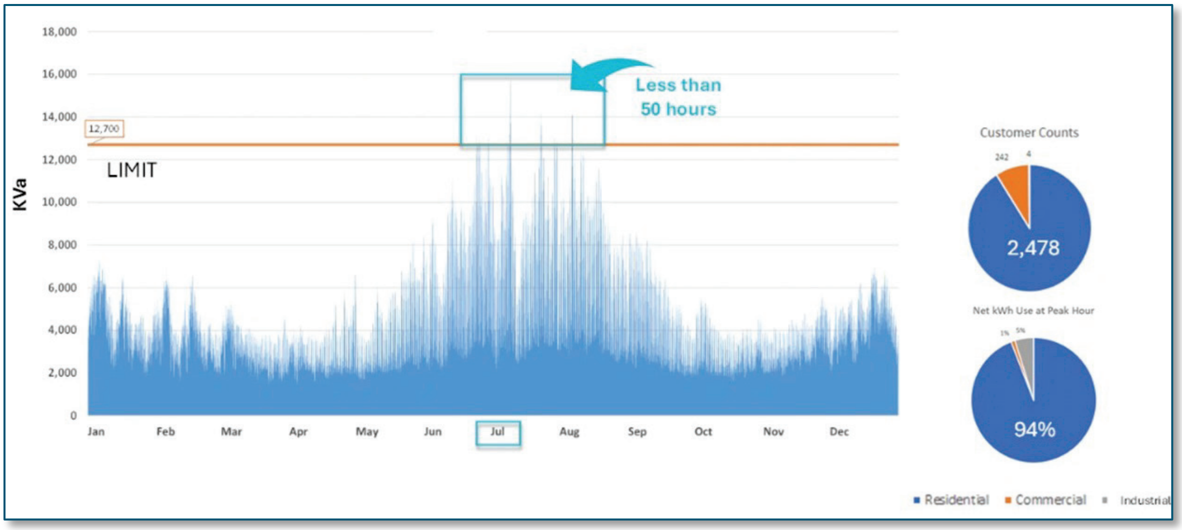


Figure 7. Duke Energy Typical Distribution Feeder Loading (Oliver, 2025)

Contingency planning is another factor affecting low distribution utilization. Utility planners perform load flow analysis to ensure that, under a contingency condition (N-1), rerouting power does not cause overloads or voltage issues on the adjacent feeder or transformer bank. This load transfer capability involves ensuring that an adjacent feeder or an alternative transformer bank has sufficient spare capacity to accept the additional load during an outage. As design and operating criteria, normal peak loading on a feeder is often limited to 60–70% of its thermal rating, and substation transformers may be operated at 75–80% of their normal rating to support load transfers. For example, Portland General Electric's (PGE's) target loading is less than 67% for feeders and less than 80% for transformers.[67]

An average mixed-customer load factor of 45% with a contingent limit of 70% yields utilization of about 31% of the normal capacity rating of a feeder or substation transformer. While this traditional planning approach provides high reliability with N-1 capability, it comes at the cost of underutilized capacity during day-to-day operations. Opportunities to improve customer load factors and better utilize flexible load and GER for reliability contingencies may lead to improved distribution utilization.

Conservation voltage reduction and Volt/VAR optimization are the most prominent approaches for improving distribution system utilization. Lowering distribution voltages within the acceptable band of the ANSI standard reduces energy losses on the network and can somewhat increase distribution capacity. For example, Dominion Energy's Voltage Optimization program leverages smart meter data to adjust system-wide voltage levels, improving efficiency and reducing overall energy use. A core element of the utility's Grid Transformation Plan, the initiative supports growing energy demand while maintaining reliable service.[68] Utilities can include conservation voltage reduction in IRP as a selectable resource or as a decrement to overall load.

[67] PGE, 2024.
[68] Dominion Energy Virginia, ND.

However, more substantive methods are needed to materially reduce distribution capacity upgrades that may be required with load growth and increasing GER adoption. Xcel Energy is addressing this challenge in a recently approved program for a battery storage network to optimize its Minnesota system and help meet growing electricity demand. The utility's Capacity Connect program will install up to 200 MW of utility-owned battery storage resources in 1–3 MW units at strategic grid locations by 2028. The approach leverages both IRP and distribution planning to identify the best customer locations for installing new battery storage resources where bulk power and local grid systems have similar load shapes. The company will integrate these large battery storage units into its system operations, charging the batteries when energy is inexpensive and dispatching batteries to address distribution and bulk power system needs and defer capital investments, maximizing benefits for ratepayers through multiple value streams (Figure 8).[69]

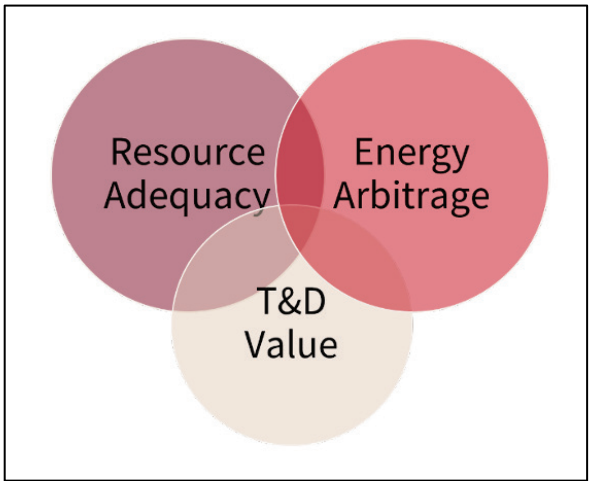


*Figure 8. Capacity*Connect Value Streams (Xcel Energy, 2025)*

The program will provide important operational experience for optimizing distribution system-connected resources for bulk system benefits. The utility expects the majority of near-term value from battery participation as a capacity resource in MISO's resource adequacy construct and additional value from participation in the energy market or avoided energy market purchases.[70] Operational experience is particularly important as utilities develop dispatching, visibility, and control capabilities.

3.3.2 GER Integration

Transparent and accurate representation of all technologies in IRP and associated procurements leads to better planning outcomes. Leading or emerging practices for modeling GERs in IRP include assessing GER adoption separately from GER operation, allowing these resources to be dispatched according to their capabilities, probabilistic modeling of GER operation on an hourly basis by customer-segment in relation to load profiles, and using up-to-date capacity accreditation practices that are technology-agnostic to enable comparison of resource adequacy contributions across different types of resources (although this practice is

[69] Xcel Energy, 2025.
[70] Ibid; Stenclik and Hostetter, 2025.

still growing in sophistication).[71] Appropriate consideration of avoided transmission and distribution (T&D) costs also is important — for example, by internalizing avoided costs in overall cost assumptions that feed into IRP models.[72] GER services for avoiding T&D upgrades require an operational potential analysis to identify predictable performance to ensure reliable operation.[73,74] Utilities can transparently document all planning assumptions, including those that may influence GER operation, such as rate and program structures and types of GER aggregations.

In areas where GERs are essential contributors to utility resource adequacy and flexibility services, GER utilization that falls short of expected contributions to grid services can erode reserve margins, requiring utilities to rely on bulk system resources and transmission capacity that can be under strain from new loads. Incorrect assumptions about GER contributions may cause underbuilding or overbuilding of bulk power resources, creating reliability issues or financial burdens for ratepayers. Realistic and verifiable GER utilization is necessary to avoid ratepayers overpaying for resources to ensure system reliability.

As utility customers continue to adopt GERs, the following planning-related analyses become increasingly important:

- *Hosting capacity analysis*, to establish the quantity of distributed generation and storage (for example, as selected in an IRP portfolio) that can safely connect to the grid in specific locations or, conversely, where distribution system investments might be needed to cost-effectively interconnect these IRP-identified resources
- *Improved interconnection procedures and new flexible connection options*, which are needed to deliver GER projects the utility selects in the IRP process on time and at scale
- *GER deliverability reviews*, which confirm that GER aggregations can safely and reliably provide wholesale services

Together, these enablers contribute to a foundation for PUCs to treat GERs as dependable, dispatchable resources. Probabilistic analysis for dependable capacity also is needed.

Hosting capacity analysis

HCA is the amount of GERs (or loads) that can be integrated at a specific location on the distribution system before requiring distribution infrastructure upgrades (or energy export limits) to maintain safety and reliability.[75] It is an engineering study based on three key operating parameters: thermal capacity, voltage quality, and protection coordination.[76,77]
The analysis provides a snapshot of a distribution system's ability to integrate GERs.
The analysis identifies grid locations where GERs can be added at minimal cost. Publicly

---

[71] ESIG, 2023; Telos Energy, report to the Illinois Commerce Commission on resource accreditation in PJM and MISO, April 2026.
[72] Biewald et al., 2024.
[73] Murdock, Goldstrom, and De Martini, 2026.
[74] Keen et al., 2026.
[75] National Laboratory of the Rockies (NLR), ND.
[76] Maryland Department of Natural Resources, ND.
[77] Electric Power Research Institute (EPRI), 2015.

available hosting capacity data provides early visibility into the likely costs and technical hurdles associated with interconnecting GER projects at specific sites.[78] This upfront transparency streamlines the interconnection process, facilitating project siting and reducing uncertainty and delays.[79] For example, to support Commission-approved procurement of 293 MW of distributed generation as part of the utility's 2022 IRP, [80] Georgia Power launched a statewide hosting capacity tool to enable prospective bidders to identify optimal interconnection locations across the distribution system. The tool streamlined procurement by directing bidders to more favorable project sites. This integration significantly enhanced efficiency, improved siting outcomes, and supported the cost-effective deployment of distributed resources to achieve the level of distributed generation capacity identified in the utility's IRP action plans.

Utilities and PUCs in some states are expanding the scope of HCA to consider longer-term implications of integrating forecasted levels of distributed generation and batteries, in addition to load growth. For example, NV Energy’s DRP forecasts hosting capacity to identify circuits that may become constrained in the future due to GER growth (Figure 9).[81] If significant rooftop solar is forecast for a particular feeder over the next five years, the DRP identifies the feeder’s current hosting capacity and any shortfall. That, in turn, informs the utility's grid upgrade plans and GER management strategies.

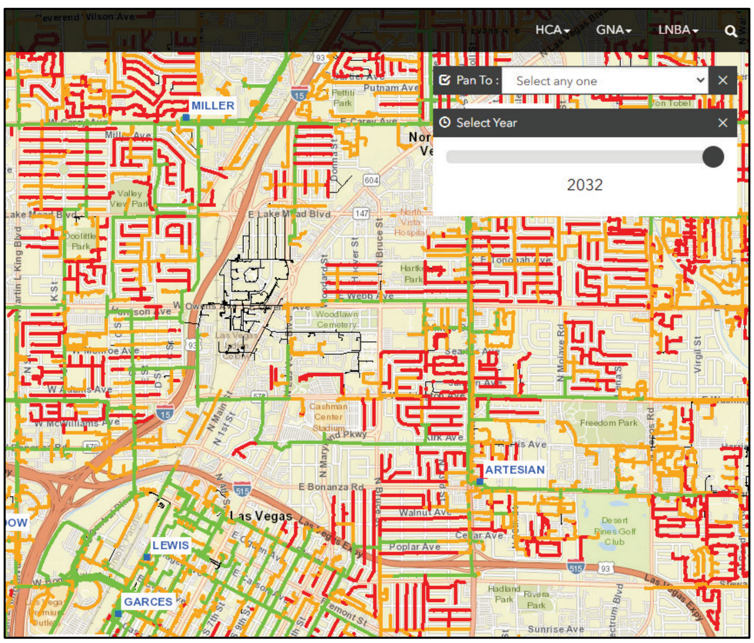


Figure 9. NV Energy 2032 Forecast Generation Hosting Capacity (NV Energy, 2025b)

By identifying the technical limits of the grid, the analysis enhances transparency across planning processes, supports the strategic and efficient integration of GERs, and helps shape investment decisions that reinforce grid reliability and system efficiency. HCA also supports the

78 For more information on HCA, see: https://www.energy.gov/cmei/vehicles/us-atlas-electric-distribution-system-hosting-capacity-maps.
79 Stanfield, Safdi, and Baldwin Auck, 2017.
80 Georgia Power, 2025.
81 NV Energy, 2025a.

development of integration cost estimates for GERs that impact their overall net costs to serve local and bulk system needs.

Forecasting hosting capacity data and identified grid upgrades can be incorporated directly into an IRP's broader least-cost optimization framework. By quantifying potential grid upgrade requirements, utilities gain the ability to balance near-term GER adoption with long-term system investment needs, improving cost-effectiveness.

Streamlining Interconnection

Utility interconnection processes in many jurisdictions throughout the country are inefficient, leading to significant backlogs that can cause material delays for GER projects. When IRPs forecast expected GER adoption at a certain pace and scale, and interconnection delays occur, utilities may face resource shortfalls. This happens when the GER capacity assumed in resource plans does not materialize in time to meet system needs. States and utilities can consider improvements related to interconnection studies, coordinating interconnection and grid planning, and cost allocation of required distribution system upgrades.[82]

Flexible Connections[83]

Flexible connection strategies involve shaping distributed resource imports and exports to remain within distribution system operating parameters (e.g., capacity and voltage limits) during periods when distribution systems are constrained (Figure 10). These strategies improve distribution system utilization, allowing more load and GER interconnections while lowering interconnection costs and/or deferring infrastructure upgrades.[84] The operating limits establish the upper and lower bounds for a given time interval for allowable import or export of power at a point of interconnection. These bounds can change across time intervals based on system conditions and anticipated constraints.

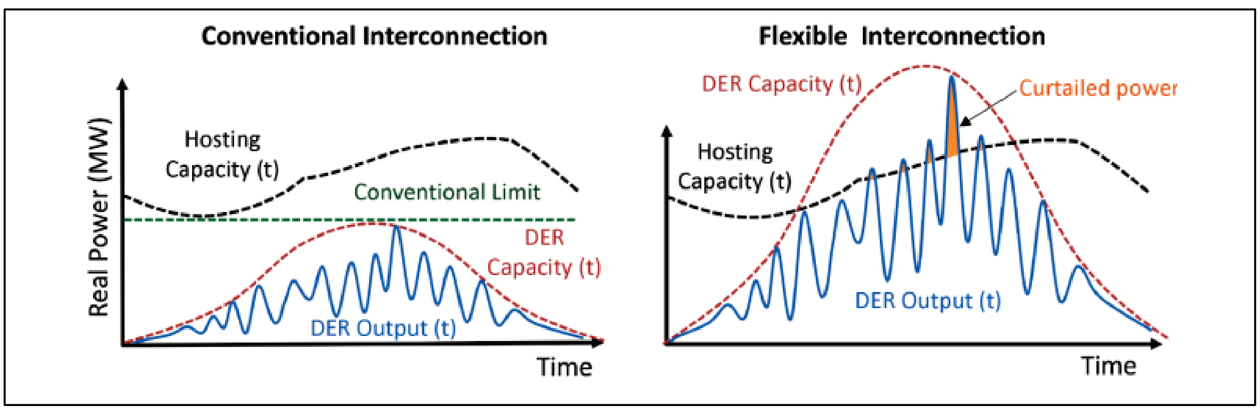


Figure 10. Conventional Interconnection Versus Flexible Interconnection (Source: EPRI, 2015)

Flexible interconnection allows for more intelligent use of the available capacity identified in enhanced distribution planning and hosting capacity analysis in exchange for modest export

82 For more information on interconnection solutions, see https://emp.lbl.gov/interconnection-innovation-e-xchange.
83 Adapted from Yu and De Martini, 2024.
84 EPRI, 2022.

curtailment. The operating limits for each energy-exporting distributed resource, or demand by a large load, are determined by 8,760 hourly forecasts and coincident hourly distribution hosting capacity. This results in seasonal, monthly, or daily operating limits for GER and large loads based on available distribution capacity at each time interval. These variable operating limits are also referred to as the dynamic operating envelope.

A 2024 CPUC decision adopted Limited Generation Profiles to enable flexible distribution interconnections. These profiles are dynamic operating limits that specify the maximum amount of energy a GER can export to the grid at specific times of year, based on available distribution capacity.[85]

Flexible connection methods can serve as a temporary or a more permanent solution. In a temporary context, flexible connections enable distributed generation, energy storage, and large loads to connect more quickly, bridging the gap until completion of scheduled distribution reinforcements. Alternatively, they can serve as a longer-term solution until other proposed distributed resources and large loads necessitate a distribution system upgrade.

Deliverability reviews

Federal Energy Regulatory Commission (FERC) Order No. 2222 (2020) revised federal regulations to remove barriers to the participation of GER aggregations in RTO/ISO capacity, energy, and ancillary services markets.[86] The order required the six affected RTOs and ISOs to revise their tariff to give electric distribution companies (utilities) up to 60 days to review proposed GER aggregations for capability, safety, and reliability. FERC has accepted the final compliance filings of the RTOs and ISOs. Utility 60-day review process and methods are under development.

The review process is designed to ensure that GER aggregations are technically sound, compliant with FERC interconnection rules, and do not introduce risks to distribution operations. The review consists of two functions: a Capability Review and a Safety and Reliability Review.

The Capability Review allows distribution utilities to confirm that each GER in an aggregation has an approved interconnection agreement and that participation in wholesale markets does not conflict with retail tariffs. The review also validates that proposed operating characteristics of GERs are consistent with their interconnection agreements and they are not receiving dual, conflicting forms of compensation. In short, the capability assessment verifies that aggregations are built from eligible, properly interconnected, and tariff-compliant resources.

The Safety and Reliability Review provides a structured opportunity for the utility to examine whether GER aggregations may pose risks to the safe and reliable operation of its distribution system. This includes evaluating dispatch profiles, hourly schedules for storage resources, and interconnection agreement limits (e.g., export caps or service restrictions). The review may

85 IREC, 2024.
86 FERC, 2020.

differentiate among different types of GERs, since each has distinct impacts on feeder operations. Such an assessment would consider hosting capacity limits, potential impacts from reverse power flow, minimum net load, and other relevant factors. If the utility identifies risks, it may recommend upgrades, operational limits, or additional studies.[87] Utilities are expected to establish a streamlined and consistent process to ensure that the 60-day review is fairly administered and supports participation in wholesale markets for projects that do not jeopardize distribution system reliability. Beyond compliance, these reviews are critical for building confidence in the deliverability of distributed generation and batteries supplying wholesale energy.

Even without regulatory mandates, the same principles apply to states without organized wholesale electricity markets. Deliverability confidence ensures that GERs included as resources in IRPs are not constrained by distribution system limits. If unidentified constraints arise, this could erode resource adequacy or require reliance on costlier resources.

Deliverability reviews will become foundational for credible resource planning and resource adequacy assessments for utilities with material levels of distribution-connected generation and batteries. This requires confidence that GER resource paths are unconstrained by local hosting limits or tariff conflicts. As such, incorporating findings of a distribution deliverability assessment, such as identified operating limits, of forecast energy injection from supply-oriented distributed generation and batteries into an IRP will be increasingly important. Strengthening this link, combined with a probabilistic-based operational potential analysis, improves certainty that GERs can be dispatched as planned, enabling planners to reduce contingency margins and better integrate GERs as reliable resources. As GER aggregations serving wholesale needs becomes more common, it will also become increasingly important to consider and clarify dispatch practices, priorities, and the impacts on distribution systems when dispatched for bulk needs.

3.4 Integrated System Analysis

As states move toward more comprehensive and coordinated approaches to electricity system planning, integration of distribution system elements in IRPs is increasing. The joint NARUC-NASEO comprehensive planning initiative[88] underscore the importance of treating these traditionally separate functions as interconnected layers of a single system, where investment decisions at one level inevitably shape options and costs at the other. This illustrates the shift underway to embed distribution system insights (e.g., values for avoided distribution system costs) and resource interactivity (e.g., value of grid services) into long-term planning and procurement processes.

3.4.1 Convergent and divergent value analysis

A divergence between bulk system peak demand and distribution feeder peak demand means that the overall electricity usage for the utility's service area might peak at a different time or have a different magnitude than the peak demand experienced by individual distribution

[87] RTOs/ISOs may require supporting documentation to substantiate these recommendations.
[88] NARUC-NASEO, 2021b.

feeders. *Convergence* occurs when local grid demand peaks coincide with bulk power system peaks, and resource benefits align at both levels of the electricity system. If peak demand is *divergent,* benefits at one level of the electricity system may be offset or diminished by another level of the electricity system, underscoring the importance of coordinated planning. The convergence or divergence of peak demands impacts the total value of GERs for the distribution and bulk power system, as illustrated in Figure 11.[89]

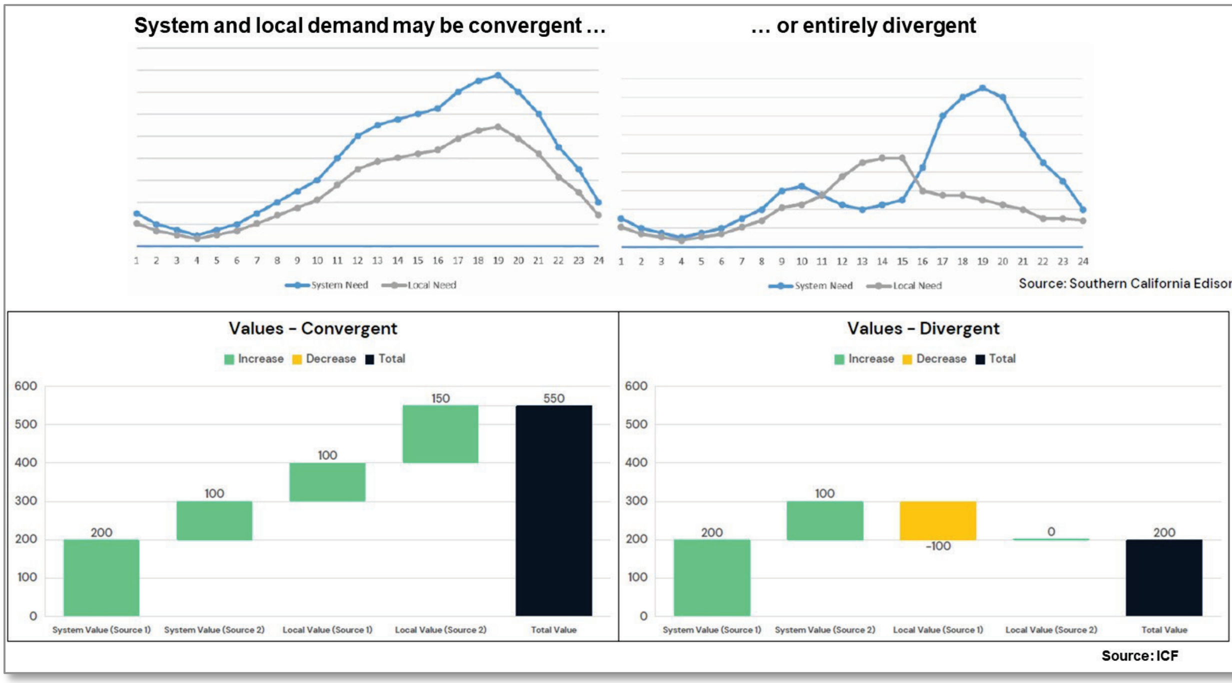


Figure 11. Alignment of System and Local Demand (Source: Southern California Edison 2024; ICF, 2026)

Alignment or divergence of peak demand can occur based on timing differences related to the net effect of bi-directional energy flows (i.e., consumption and export) for individual feeders or substations due to customer composition (e.g., residential, commercial, light industrial), interconnected distributed generation and battery storage, and weather (e.g., micro-climate zones), compared to system peaks and weather patterns across a service territory.

- <u>Diverse load profiles across feeders</u> - Different types of loads on various feeders may peak at different times. For example, residential feeders might peak in early morning or evening, whereas commercial and industrial feeders might experience peak demand during daytime business hours.
- <u>Weather variations</u> - Service area and regional differences in temperature and weather conditions, combined with differences in building heating and cooling technologies, can lead to variations in peak demand across different parts of distribution and bulk power systems. This can occur when hot weather in a local area causes a surge in air conditioning use and thus a peak on a particular feeder, while the overall bulk system might not be at its peak at that moment. This also can be true if bulk system planning

---

[89] EPRI, 2023; SEE Action, 2020; De Martini, Succar and Cook, 2024; SCE 2024 at 28; ICF, 2026.

includes different climate zones across a service territory, as these can exhibit more granular microclimate variations from the system average zone temperatures and humidity. For example, PGE observed that the east side of its service territory peaked heavily in winter, predominantly due to electric baseboard heating.[90] In contrast, the west side had a higher concentration of gas heat and electric heat pumps, resulting in lower winter demand. The west side had high peaks in the summer due to air conditioning load, while the east side traditionally had low saturation of cooling equipment.[91]

- GER Integration - Distributed generation, battery storage, and large loads sited on individual distribution feeders can shift the timing and magnitude of net feeder load independently of bulk system conditions because the drivers of distribution-level load (e.g., feeder-specific EV charging behavior, rooftop PV penetration, localized weather) are not necessarily correlated with the drivers of system-wide peak demand.
    - For example, a feeder with a high concentration of public EV charging and residential air conditioning may see its net load peak shift earlier in the day, driven by daytime charging activity and rising cooling load as ambient temperatures climb, while the bulk system peak may occur later, in the early evening, once solar output declines and aggregate cooling and lighting load across the broader territory reaches its system-wide maximum. The result is a feeder-level peak that is out of phase with the bulk system peak. In this divergent case, GER used for distribution may not create value for the bulk power system.
    - In a convergent case where peaks are aligned, by contrast, the same resource that serves a distribution peak also provides bulk power system peak-management benefits.
    - In certain divergent cases, however, a GER may have sufficient capability (e.g., state of charge, available capacity) to be dispatched to serve the distribution-level need during its peak window while still retaining capability to serve the bulk system during its separate peak window. A feeder-level GER and load forecast, along with the corresponding hourly feeder power flow analysis, can enable identification of the value potential for both feeder and bulk power system peak management.
- Diversity Factor - The diversity factor describes how the sum of individual peak demands on multiple feeders affects demand on the originating substation. For example, while individual feeders might have high peak demands, their peaks may not coincide, resulting in a lower overall peak for the substation interface to the bulk power system. This is why substation-level GER aggregations spanning multiple feeders may not always address feeder-level constraints. The participating GER may not be located on the constrained feeder or feeder section, or may not be dispatched at times that coincide with individual feeder constraints.[92] Analysis of distribution constraints should first focus on the specific locations and characteristics of individual constraints.

[90] Murtaugh, 2025.
[91] Keeling et al., 2021.
[92] De Martini, Succar, and Cook, 2024.

Afterward, the constraints may be collectively assessed at a higher level to consider larger GER aggregations.

Assessing the relative convergence and divergence of peaks and how resources impact those peaks informs different value streams of distribution-sited resources that may feed into rate designs, resource operation (e.g., storage dispatch or charging), and resource siting. For example, Xcel Energy's Capacity*Connect program aims to site batteries where distribution and bulk loads coincide to reduce or defer investment.[93]

3.4.2 Co-optimizing Bulk and Distribution System Resources

A central element of comprehensive system planning is co-optimization of bulk power and distribution connected resources. This multi-level planning approach explicitly accounts for interdependencies across the grid. It involves aligning investment strategies and modeling assumptions to ensure that GER impacts, including changes in electricity consumption and peak demand, are incorporated into bulk power system plans. Granular DSP outputs are systematically aggregated into higher-level analyses, rolling up from feeder- and substation-level assessments to sub-transmission nodes and regional bulk system models.[94]

Planners also evaluate system stability and power flow impacts to understand how GERs influence both distribution and bulk power system operations. Importantly, this approach helps distinguish between convergent value cases in which GERs benefit both levels of the electricity system, and divergent cases in which a resource that relieves local constraints may not serve broader system needs.

For example, Puget Sound Energy (PSE) in Washington state is developing an ISP, to be filed on April 1, 2027, that incorporates distribution planning, as required by statute. The ISP builds on previous utility efforts to include DSP elements in IRP. PSE's 2021 IRP included a 10-year "Delivery System Analysis" that included visibility, control, reliability, GER integration, cybersecurity, and major infrastructure needs. Figure 12 depicts PSE's iteration between this analysis and IRP, with the delivery analysis providing avoided T&D values and NWA forecasts, and IRP providing the value of systemwide grid services back to the delivery analysis.

[93] Xcel Energy, 2025.
[94] See ESIG, 2025, for additional information.

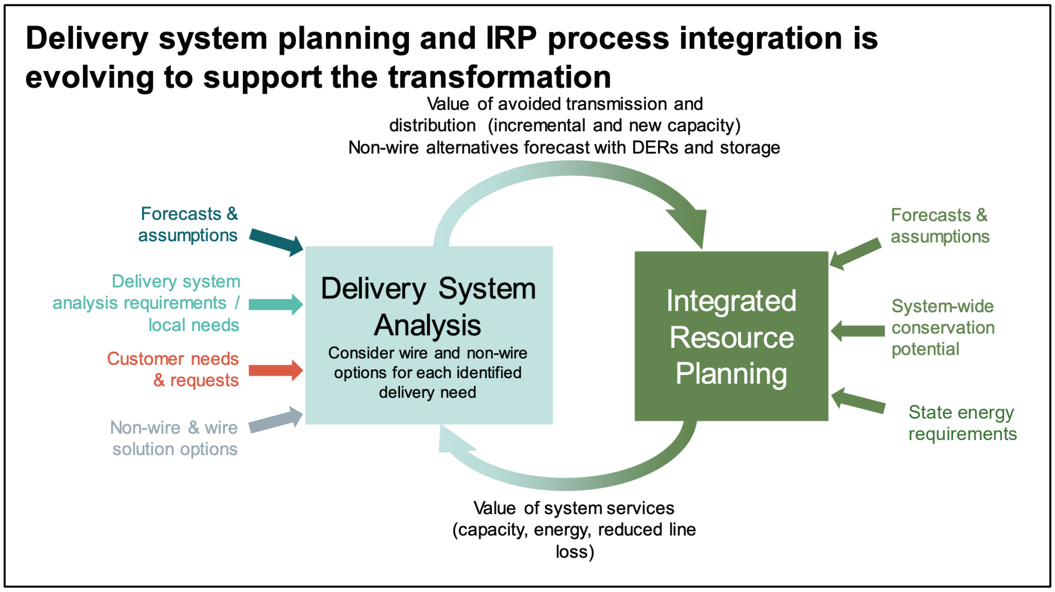


Figure 12. PSE Iteration between DSP and IRP (Adapted from PSE, 2024)

For the 2027 ISP, PSE's DSP priorities are to:

- Invest in T&D systems to timely meet load growth
- Build modeling approaches to evaluate distribution investments in ISP scenarios
- Advance NWAs and GER deployment to optimize GER utilization for system needs.[95]

Figure 13 shows PSE's planning schedule. The utility is building inputs and conducting modeling across different levels of the electric and gas systems at the same time, with built-in opportunity for updates if needed about a year after developing T&D inputs. This aligns with PSE's process for planning distribution system investments based on annually refreshed load forecasts.[96]

[95] PSE, 2025.
[96] Ibid.

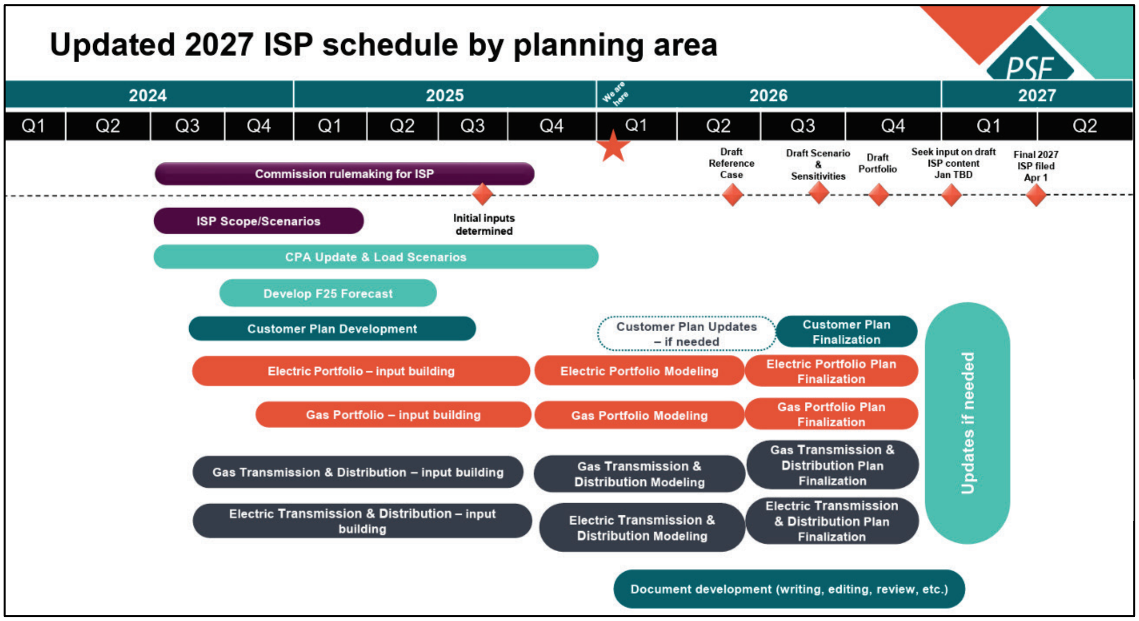


Figure 13. PSE ISP Workstream Sequencing (Adapted from PSE, 2026). Diamonds indicate milestones.

<u>Integration Processes</u>

Integrated planning across bulk power and distribution systems depends on aligned timelines, data, assumptions, and analyses. Successful integration processes also require strong engagement and governance. Transparent processes that incorporate stakeholder input, supported by regulatory frameworks for integrated planning that foster alignment among the utility, PUC, and stakeholders, facilitate reliable and cost-effective outcomes.

Toward aligning timelines, distribution system forecasts and analyses can be extended across the entire IRP horizon. For example, Hawaiian Electric uses LoadSEER to "statistically represent the geographic, economic, and weather diversity across a utility's service territory and use that information to forecast how circuit- and transformer-level hourly load profiles will change over the next 30 years."[97]

Because DSP may be updated more frequently than IRP, thoughtful workstream sequencing can allow such distribution-level findings to be incorporated sufficiently early to inform IRPs, ensuring that bulk power system plans reflect the operational realities of rapidly evolving local grids. In this way, electricity system planning moves beyond siloed exercises toward a unified, interactive process that better supports reliability and affordability goals.

Synchronized planning cycles enable distribution feeder- and substation-level insights to inform IRPs. For example, net load forecasts based on granular GER forecasts may impact the location of resource and transmission needs for the bulk power system. Suppose an IRP identifies a particular quantity of distributed generation and batteries as part of the least-cost resource mix, but distribution-level analysis shows that local grid upgrades to interconnect those resources are cost-prohibitive. In that case, the utility would procure more transmission-

[97] Hawaiian Electric, 2020 at 8.

level resources instead. Conversely, distributed generation and batteries may be needed if utility-scale resources or transmission cannot be developed in time to meet projected loads. For example, significant transmission constraints are driving a greater role for customer-sited resources in PGE's resource planning process.[98]

For example, Duke Energy's Integrated System and Operations Planning (ISOP)[99] process synchronizes distribution, transmission, and resource planning by aligning timelines, data inputs, and scenarios. The IRP provides a 15-year outlook, while distribution and GER forecasts are updated more frequently. ISOP bridges these cycles by establishing a continuous feedback loop, where each plan informs the others. This ensures that distribution, transmission, and resource strategies are developed in parallel, using shared assumptions rather than isolated, sequential processes.

A central feature of ISOP is its unified data and forecasting platform, which integrates disparate data into a common system. This enables scenario-driven long-term resource forecasts to be combined with bottom-up distribution analysis and supports coordinated identification of electricity system needs based on information flow across planning levels and horizons. That includes considering distribution hosting capacity analysis for load growth and GER adoption in IRP decisions.[100]

ISOP also institutionalizes evaluation of non-traditional solutions such as batteries that could defer or avoid utility grid investments. When assessing the relative costs of such solutions compared to traditional grid investments, Duke applies IRP-derived values such as avoided supply-side costs and bulk capacity contributions to evaluate distribution-level alternatives on an equal footing with supply-side infrastructure. The process allows Duke to optimize system investments.

Another example is New York's Coordinated Grid Planning Process to improve the integration of resource procurement plans with distribution, transmission, and NYISO planning. [101,102] While tactics have evolved somewhat over time, the initial process envisioned six stages over a 24-month cycle:

- **Stage 1 – Data collection, scenario definition, and capacity expansion modeling:** Selection of inputs and development of assumptions to support least-cost modeling and scenario analysis, focused on identifying bulk generation buildout scenarios using capacity expansion modeling

[98] PGE, ND.
[99] Keen et al., 2023.
[100] Duke Energy Progress and Duke Energy Carolinas, 2023.
[101] Central Hudson Gas & Electric Corporation; Consolidated Edison Company of New York, Inc.; Long Island Power Authority; National Grid (upstate); New York State Electric & Gas Corporation; Orange & Rockland Utilities, Inc.; and Rochester Gas and Electric Corporation.
[102] New York DPS, 2021, at 19.

- **Stage 2 – Network model development:** Development of short circuit and power flow models, over a 20-year period, to identify areas where resources selected by the capacity expansion model can use local T&D assets
- **Stage 3 – Local T&D assessment:** Evaluation of T&D investment needs to enable GERs and utility-scale generation; consideration of distribution upgrades and NWAs to meet grid needs
- **Stage 4 – Review of preferred solutions:** Assessment of systemwide impacts of T&D upgrades identified in the local T&D assessment
- **Stage 5 – Least-cost planning assessment:** Determination of the least-cost resource portfolio considering system limitations identified in stage 3 and the portfolio of T&D solutions developed in stage 4
- **Stage 6 – Cycle I final report:** Production of a final report taking into consideration stakeholder input[103]

Stakeholder input occurs through the Energy Policy Planning Advisory Council, which provides feedback on planning assumptions and analytical approaches.[104] Figure 14 illustrates the Coordinated Grid Planning Process.

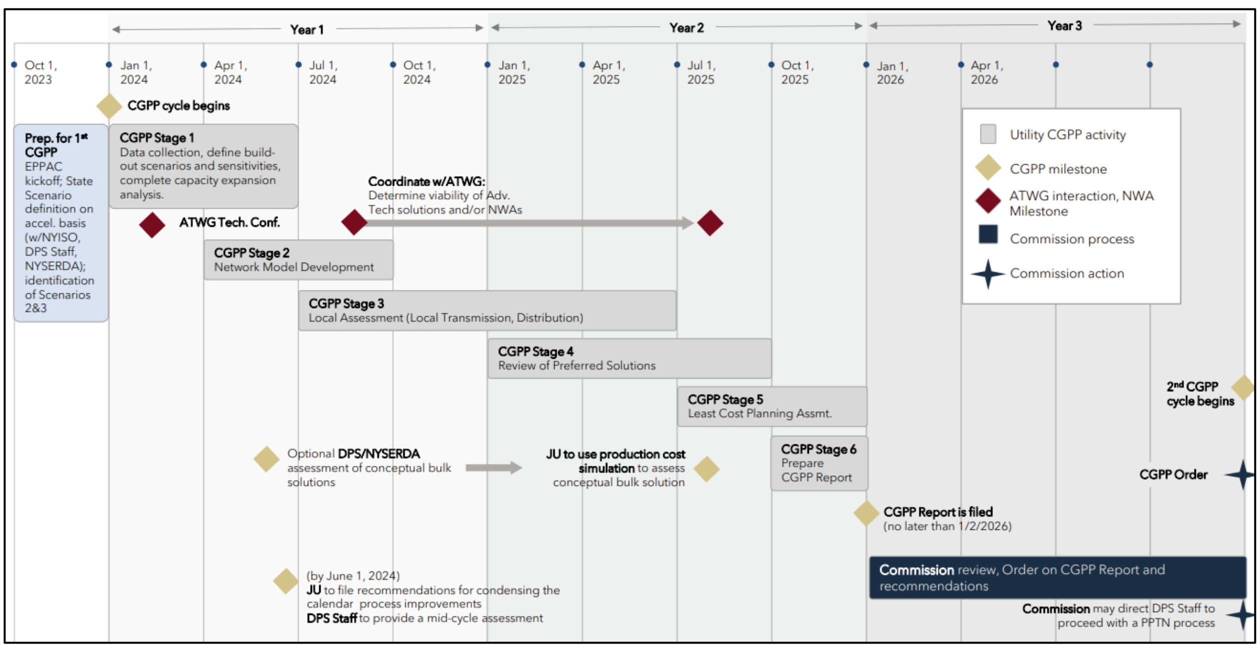


Figure 14. Coordinated Grid Planning Process Timeline (Burrell, 2024) – Acronyms include Advanced Technologies Working Group (ATWG), Coordinated Grid Planning Process (CGPP), Energy Policy Planning Advisory Council (EPPAC), Department of Public Service (DPS), Joint Utilities (JU), New York Independent System Operator (NYISO), New York State Energy Research and Development Authority (NYSERDA), Non-wires alternative (NWA), and Public Power Transmission Need (PPTN)

3.4.3 Coordinated Procurement Practices

As distribution-level needs grow more complex and GER adoption increases, many states are moving toward utility procurements that solicit both distribution and bulk system-connected

[103] New York DPS, 2023 at 8.
[104] See https://dps.ny.gov/energy-policy-planning-advisory-council.

resources to meet grid needs. Such coordinated procurement ensures that solicitations reflect both bulk-system needs identified in the IRP and locational needs identified through DSP. A roadmap developed through the NARUC-NASEO Task Force on Comprehensive Electricity Planning envisions procurement as part of a framework that identifies electricity system needs through integrated distribution and resource planning. Alternatively, solutions identified through distribution NWA procurement also may address a need identified in the IRP. In this approach, procurement serves as both an output of integrated planning and a mechanism for validating planning assumptions (e.g., cost and performance data) through market response (e.g., bids submitted in response to a request for proposals).[105]

Distribution planning also informs deliverability-based screening that affects which resources identified in the IRP move forward into procurement. Utilities increasingly use DSP to validate that proposed GER portfolios can be reliably interconnected and deliver the modeled services. For example, Hawaiian Electric uses iterative modeling across transmission, distribution, and generation systems to verify that GER portfolios identified through planning are physically deliverable before they are procured. When distribution constraints emerge, the utility adjusts the analysis to consider the cost of required distribution system upgrades to make sure the aggregated GER resource is still selected as cost-effective in the plan before procurement.[106]

In lieu of competitive procurements, utilities may develop programs or rate designs based on IRP findings. Hawaiian Electric modeled the value of grid services from GERs to inform program design and rate-based price signals.[107]

[105] NARUC-NASEO, 2021a.
[106] Hawaiian Electric, 2023.
[107] Ibid.

4. Summary of Methods in Practice

Each of the procedural and analytical coordination methods described in Chapter 3 are in use or are being tested today. Table 5 summarizes tactics and key takeaways from case study examples of utilities across the country using these practices. The Lab's detailed case studies provide additional information on how utilities are implementing these practices that utilities and states can adapt for their jurisdiction.

Common themes include:

- Sharing forecasts across IRP and DSP, including disaggregating systemwide forecasts
- Deploying distribution system optimizations, such as conservation voltage reduction, and incorporating the impacts into IRP modeling
- Using a roadmap to improve utility planning processes over time and establish a shared vision among stakeholders

Table 5. Key Findings from Utility Case Studies

Utilities and Jurisdiction	Distribution System Elements in IRP	Takeaways
	Integrated System Planning Practices	
Duke Energy (NC, SC, IN)	• Coordinates generation, transmission, and distribution planning through advanced analytics, scenario alignment, and iterative modeling • Identifies distribution-level technologies, such as conservation voltage reduction, to include as resources in IRP	• Iterative data and information exchange across planning teams is critical • DSP can inform locational avoided costs for IRP
Salt River Project (AZ)	• Conducts ISP using a single set of forecasts and assumptions • Plans distribution capacity to optimize substation upgrades across ISP scenarios • Identifies in distribution enablement roadmap how local grid planning will become more sophisticated in future ISP iterations	• Tying distribution capacity planning and optimization to bulk system resource siting can help cost-effectively meet system needs
	IRPs that Include Distribution System Elements	
Dominion Energy (VA)	• Includes a distribution planning roadmap • Focuses IRP analysis of distribution elements on GER forecasting, hosting capacity analysis, and locational value assessment	• IRP recognizes that strategic GER siting, streamlined distribution-level interconnection, and advanced technologies benefit both the local grid and bulk power systems • The distribution planning roadmap describes grid modernization and identifies strategies for improving modeling capabilities and streamlining workflows over time • Distribution system modeling remains procedurally and analytically separate from resource modeling
DTE and Xcel Energy (MI)	• Uses forecasts consistent with DSP • Uses improved distribution analytics	• Setting aspirational goals for integration helps engage all parties toward a common end-state • Stakeholder engagement can be an effective tool for advancing planning capabilities because parties can encourage a focus on coordinated planning and bring emerging practices into the record of the proceeding

Utilities and Jurisdiction	Distribution System Elements in IRP	Takeaways
Idaho Power (ID, OR)	• Uses disaggregation and reconciliation tactics to align IRP and DSP forecasts • Models distribution-sited batteries for T&D deferral in IRP	• System-wide forecasts serve as the basis for granular DSP forecasts • Near-term actions identified in the DSP are included as assumptions in the IRP
Indiana Michigan Power (IN, MI)	• Reconciles IRP forecasts with granular, short-term forecasts • Includes grid modernization efforts in IRP to inform NWAs and improve load forecasting	• Planning requirements in one state may have spillover effects for a multi-jurisdictional utility that applies improved practices across its service area
Minnesota Power (MN)	• Uses GER forecasts and assumptions consistent with DSP and considers whether aggregated GERs can provide peak-hour capacity services • Applies a Grid Essential Services framework that uses multiple analyses to evaluate whether T&D systems can reliably support future resource portfolios	• New planning tools enhance grid visibility and strengthen analytical coordination
Public Service Company of Oklahoma (OK)	• Models distribution-level capacity savings from conservation voltage reduction • Is developing an integrated planning roadmap through its parent company	• Despite a lack of formal requirements, the utility includes distribution elements in its IRP to provide greater visibility into capital spending
Southern California Edison (CA)	• Disaggregates statewide common forecasts for use in IRP and DSP • Uses hosting capacity and constraint analysis to inform resource siting	• Planning coordination benefits from a single data set for inputs and assumptions
Vermont Electric Cooperative and Green Mountain Power (VT)	• Aligns inputs and assumptions across utilities, a statewide transmission company, commercial customer representatives, energy supply companies, and other and other stakeholders through transmission planning process • Deploys distribution assets and NWAs at the transmission level to defer or avoid T&D upgrades	• Established discussion forums are important for aligning processes with multiple entities involved

5. Conclusion and Leading Practices Checklist

Electricity system planning is increasing in sophistication to more effectively plan for utility investments to meet local grid and systemwide needs at least cost. With a growing focus on distribution system spending and affordability, utilities, PUCs, and stakeholders are advancing IRP practices to provide greater visibility into electricity system needs and improve decision-making under uncertainty. In particular, identifying key linkages between distribution and bulk power systems — and, where appropriate, conducting analyses and implementing solutions across both domains — improve cost-effectiveness of electricity system spending.

Integrating distribution system elements in IRP offers significant value, including:

- Optimized electricity system investments
- Reduced utility costs to meet growing loads
- Greater insight into utility expenditures that are driving increases in electricity rates
- Reduced functional silos at utilities
- Improved plan credibility

At the same time, integrated or coordinated planning activities require significant time and resources for the utility, PUC, and stakeholders and are still in early stages in most parts of the country. Additional experience will identify which practices provide the greatest value for different planning contexts.

The following checklist summarizes leading practices identified in this study to help guide integration of distribution system elements in IRP using processes that are transparent, data-driven, and capable of optimizing investments across all levels of the electricity system. While the checklist includes the primary actor(s) for each item — PUCs, utilities, or both — stakeholder engagement is a hallmark of effective planning processes. For example, State Energy Offices and utility consumer advocates play important roles in identifying state and utility customer interests and actions that support those interests.

Action	Primary Actor(s)	Primary Benefit(s)
Regulatory & Institutional Alignment		
☑ Develop regulatory frameworks for integrated or coordinated system planning	PUCs	Establishes guidance and expectations for planning improvements
☑ Align utility regulatory guidance for IRP and distribution system planning (e.g., specify expectations for consistent forecasts and scenarios)	PUCs	Specifies how planning coordination or integration will occur
☑ Develop a roadmap to improve practices over time and establish a common vision	Utilities	Outlines a long-term vision toward integrating distribution and bulk power system planning and tangible steps to achieve benefits
Aligned Timelines & Horizons		
☑ Sequence planning cycles so distribution insights (e.g., available hosting capacity) feed into IRP decisions on time, and vice versa (e.g., quantity of GERs selected in IRP)	PUCs	Facilitates timely availability of data inputs to coordinate or integrate planning processes
Stakeholder Engagement & Transparency		
☑ Share scenarios, assumptions, and results openly with public utility commissions and stakeholders to solicit input on consistency	Utilities	Enables feedback on assumptions, inputs, and processes to make use of external expertise and stakeholder engagement in regulatory review
☑ Incorporate stakeholder input from various forums into unified forecast assumptions, scenario design, and review processes	Utilities	Facilitates consideration of stakeholder interests and up-to-date knowledge from external experts
Common Data & Assumptions		
☑ Establish unified methodologies, associated load and grid-edge resource (GER) forecasts, and adoption scenarios across IRP and distribution planning	Utilities, PUCs	Aligns forecasts and scenarios to reduce potential conflicts between planning outcomes
☑ Maintain a unified integrated data set in an accessible repository for sharing inputs and results	Utilities	Allows all utility planners to use the same information to achieve least-cost outcomes
Disaggregated Distribution Forecasting		
☑ Align IRP and feeder and substation-level distribution forecasts through a reconciliation method to capture both local and bulk system needs	Utilities	Enables utilities to plan consistently across distribution and bulk power systems

Hosting Capacity & Deliverability		
☑ Assess results of hosting capacity and GER deliverability studies in the IRP process	Utilities	Determines whether GERs can deliver services identified in IRP
☑ Publish hosting capacity maps/tools to guide developer siting decisions for procurements coming out of IRPs	Utilities, PUCs	Enables more efficient siting of distributed generation and storage on local grids
Convergent vs. Divergent Value Analysis		
☑ Screen all eligible identified electricity system needs for cost-effective non-wires alternatives	Utilities	Evaluates all potential solutions to grid needs on equal footing to identify least-cost solutions to grid needs
☑ Identify when, where, and how GERs provide simultaneous (convergent) benefits to bulk power and distribution needs and evaluate these potential solutions in more detail	Utilities	Maximizes benefits across local and systemwide needs
☑ Flag cases where GERs help one level of the electricity system but not the other (divergent) and determine possible mitigations	Utilities	Enables more effective siting of distribution assets to minimize grid constraints or violations
Bulk Power & Distribution System Resource Co-Optimization		
☑ Use technology-neutral procurements	Utilities	Identifies the most cost-effective solutions to electricity system needs
☑ Include GERs as a selectable resource in IRPs and use technology-neutral methodologies for performance accreditation to allow GERs to contribute to resource adequacy assessments	Utilities	Avoids overbuilding and associated costs
☑ Incorporate findings from coordinated planning into procurement processes and validate planning assumptions for cost and performance based on procurements	Utilities	Activates planning to acquire the most cost-effective solutions to electricity system needs and improves information used in the next planning cycle

References

Biewald, B., D. Glick, S. Kwok, K. Takahashi, J.P. Carvallo, and L. Schwartz, 2024, *Best Practices in Integrated Resource Planning: A Guide for Planners Developing the Electricity Resource Mix of the Future*, Lawrence Berkeley National Laboratory and Synapse Energy Economics, November 11. https://emp.lbl.gov/publications/best-practices-integrated-resource.

Brown, D.P., and L. Muehlenbachs, 2023, *The Value of Electricity Reliability: Evidence from Battery Adoption*, Resources for the Future, April 14. https://media.rff.org/documents/WP_23-10.pdf.

Burdick, A., J. Hooker, L. Alagappan, M. Levine, and A. Olson, 2024, *Integrated System Planning: Holistic Planning for the Energy Transition*, Energy and Environmental Economics, Inc., October. https://www.ethree.com/wp-content/uploads/2024/10/E3-ISP-Whitepaper.pdfhttps://www.ethree.com/wp-content/uploads/2024/10/E3-ISP-Whitepaper.pdf

Burrell, K., 2024, *Overview of the Coordinated Grid Planning Process*, August 6. https://www.nyiso.com/documents/20142/46217988/06a_2024_CGPP_Update_ESPWG_20240806_vFinal.pdf/f2cc1e81-689d-1982-774f-3c047897ed34.

California Public Utilities Commission (CPUC), 2024a, *Decision 24-10-030 Adopting Improvements to Distribution Planning and Project Execution Process, Distribution Resource Planning Data Portals, and Integration Capacity Analysis Maps*, Rulemaking 21-06-017, filed October 17. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M544/K154/544154869.PDF.

CPUC, 2024b, *Decision R.21-06-017 Adopting Improvements to Distribution Planning*, Agenda ID #22920, filed September 13. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M539/K999/539999224.PDF.

Carvallo, J.P., A. Sanstad, and P. Larsen, 2019*. Exploring the Relationship Between Planning and Procurement in Western U.S. Electric Utilities*, Energy Journal Volume 183, September 15. https://www.sciencedirect.com/science/article/abs/pii/S036054421931254Xhttps://www.sciencedirect.com/science/article/abs/pii/S036054421931254Xhttps://www.sciencedirect.com/science/article/abs/pii/S036054421931254X.

Code of Maryland Regulations, 2025, Chapter 15 – Electricity System Planning 20.50.15, November 24. https://regs.maryland.gov/us/md/exec/comar/20.50.15.

De Martini, P., J. Taft, A. De Martini, and M. Hall, 2022, *Integrated Resilient Distribution Planning*, Pacific Northwest National Laboratory and Newport Consulting, PNNL-32883. https://gridarchitecture.pnnl.gov/media/advanced/Integrated_Resilient_Distibution_Planning.pdf.

De Martini, P., S. Succar, and P. Cook, 2024, *Sourcing Distributed Energy Resources for Distribution Grid Services*, U.S. Department of Energy Office of Electricity. https://www.energy.gov/sites/default/files/2024-12/Sourcing%20DER%20for%20Dist%20Services%20final%2012.17.24.pdf.

Dominion Energy Virginia, ND, “Voltage Optimization,” accessed April 24, 2026. https://www.dominionenergy.com/about/delivering-energy/electric-projects/energy-grid-transformation/grid-resiliency-projects/voltage-optimization.

Duke Energy Progress (DEP) and Duke Energy Carolinas (DEC), 2023, *Summer 2023 ISOP Informational Report*, September 6. https://www.duke-energy.com/-/media/pdfs/our-company/isop/summer-2023-isop-informational-report.pdf?rev=1611787eda944f15b85625e2e25a0a9b.

Electric Power Research Institute (EPRI), 2015*, Distribution Feeder Hosting Capacity: What Matters When Planning for DER?,* April. https://restservice.epri.com/publicdownload/000000003002004777/0/Product.
EPRI, 2022, *Active Resource Integration Project Techno-Economic Analysis of Flexible Interconnection*, October. https://www.epri.com/research/programs/067418/results/3002025504.
EPRI, 2023, *Procuring Services from Distributed Energy Resources*, technical brief, December. https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/yrnwa/yrnwa-20240611-3-Distribution-Simulations-3002028581.pdf. https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/yrnwa/yrnwa-20240611-3-Distribution-Simulations-3002028581.pdf. https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/yrnwa/yrnwa-20240611-3-Distribution-Simulations-3002028581.pdf
Energy Systems Integration Group (ESIG), 2023, *New Design Principles for Capacity Accreditation*, Redefining Resource Adequacy Task Force. https://www.esig.energy/new-design-principles-for-capacity-accreditation.
ESIG, 2025, *Integrated Planning Guidebook: A Practical Coordination Framework for Electricity Planners.* A report series by the Integrated Planning Task Force, May. https://www.esig.energy/integrated-planning/.
ESIG, 2026, *Spring Technical Workshop Session 2A: Proactive Distribution System Planning*, March 16. https://www.esig.energy/event/2026-spring-technical-workshop/.
Eversource, 2024, *Provisional System Planning Tariff*. https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/19496841.
Federal Energy Regulatory Commission (FERC), 2020, Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators, Order 2222 Issued September 17. https://www.ferc.gov/sites/default/files/2020-09/E-1_0.pdf.
Georgia Power, 2025, *2025 Integrated Resource Plan*. https://services.psc.ga.gov/api/v1/External/Public/Get/Document/DownloadFile/221233/102406.
Hawaii Public Utilities Commission, 2024, *Order No. 40651 Accepting the 2023 Final IGP Report and Providing Guidance,* Docket No. 2018-0165, filed March 7.
Hawaiian Electric, 2020, *Distribution Planning Methodology*. https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/stakeholder_engagement/working_groups/distribution_planning/20200602_dpwg_distribution_planning_methodology.pdf.
Hawaiian Electric, 2023, *Integrated Grid Plan*, May. https://hawaiipowered.com/igpreport/IGP-Report_Final.pdf.
Homer, J S., Y. Tang, J D. Taft, A C. Orrell, D. Narang, M. Coddington, M. Ingram, and A. Hoke, 2020, *Electric Distribution System Planning with DERs – High-level Assessment Tools and Methods*, Modernization Laboratory Consortium. Pacific Northwest National Laboratory (PNNL), March. https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-28138.pdf.
Homer, J., A. Cooke, L. C. Schwartz, G. Leventis, F. Flores-Espino, M. Coddington, 2017, *State Engagement in Electric Distribution System Planning,* Lawrence Berkeley National Laboratory and Pacific Northwest National Laboratory, PNNL-27066, December. https://emp.lbl.gov/publications/state-engagement-electric.
ICF, 2026, ESIG DER Grid Service Value and Dependability Task Force presentation, June 4. https://www.esig.energy/resources/presentations/?working-group=distributed-energy-resources.
Interstate Renewable Energy Council (IREC), 2024, Milestone Decision by California Regulators Approves the Use of DER Schedules to Avoid Interconnection Upgrades, March.

Available online: https://irecusa.org/blog/irec-news/milestone-decision-by-california-regulators-approves-the-use-of-der-schedules-to-avoid-interconnection-upgrades/
Kahrl, F., A. D. Mills, L. Lavin, N. Ryan, and A. Olsen, 2016, *The Future of Electricity Resource Planning*, Lawrence Berkeley National Laboratory, September. https://emp.lbl.gov/publications/future-electricity-resource-planning.
Kahrl, F., and L. C. Schwartz, 2021, *All-Source Competitive Solicitations: State and Electric Utility Practices*, Lawrence Berkeley National Laboratory, March. https://emp.lbl.gov/publications/all-source-competitive-solicitations.
Keeling, J., F. Schaefer, E. Goldman, T. Light, R. Hledik, and S. Sergici, 2021, *PGE DER and Flexible Load Potential – Phase 1*, Cadeo and Brattle for Portland General Electric, July 7. https://assets.ctfassets.net/416ywc1laqmd/1sMpwIkeZ0Imb9FuEA7F2i/128e4ffc0bc044f2fde8dcd7cbdc03c6/2021-09-17-pge-der-flex-load-potential-phase1.pdfhttps://assets.ctfassets.net/416ywc1laqmd/1sMpwIkeZ0Imb9FuEA7F2i/128e4ffc0bc044f2fde8dcd7cbdc03c6/2021-09-17-pge-der-flex-load-potential-phase1.pdf.
Keen, J., E. Pohl, N. Mims Frick, J.P. Carvallo, and L. C. Schwartz, 2023, *Duke Energy's integrated system and operations planning: A comparative analysis of integrated planning practices*, Lawrence Berkeley National Laboratory, June. https://emp.lbl.gov/publications/duke-energy-s-integrated-system-and
Keen, J., J.P. Carvallo, et al., 2026, Distribution System Adequacy: Concept and Techniques for Risk-Informed Assessments of Infrastructure Investments, National Laboratory of the Rockies and Lawrence Berkeley National Laboratory. (Forthcoming.)
Lawrence Berkeley National Laboratory (LBNL), 2026, State Electric Distribution Planning Practices, accessed June 2026. https://emp.lbl.gov/state-electric-distribution-system-planning-practices.
Maryland Department of Natural Resources, ND, "Hosting Capacity FAQ," Accessed April 24, 2026. https://dnr.maryland.gov/pprp/Pages/hosting-capacity-faq.aspx#a.
Maryland Public Service Commission (MD PSC), 2025, *COMAR 20.50.15 Electric System Planning Proposed Regulations*. https://dsd.maryland.gov/MDRIssues/5218/Assembled.aspx#_Toc207742793.
Mims Frick, N., L. C. Schwartz, and A. Sandonato, 2025, *Appendix: Regulatory Challenges With Utility Investment Planning and Cost Recovery for Grid Modernization*, Lawrence Berkeley National Laboratory, April. https://eta-publications.lbl.gov/sites/default/files/2025-12/grid_mod_investment_20251204.pdf.
Murdock, D., O. Goldstrom, and P. De Martini, 2026, Distribution Operational Potential of Grid Edge Resources, Pacific Northwest National Laboratory. (Forthcoming.)
Murtaugh, D., 2025, Interview regarding innovative utility practices.
National Association of Regulatory Utility Commissioners – National Association of State Energy Officials (NARUC-NASEO), 2021a, *Blueprint for State Action: NARUC-NASEO Task Force on Comprehensive Electricity Planning,* February. https://pubs.naruc.org/pub/14F19AC8-155D-0A36-311F-4002BC140969?_gl=1*1lyow80*_ga*MjM0NzU0MzAwLjE3NzA2NTUzNDA.*_ga_QLH1N3Q1NF*czE3ODE1NTEzODUkbzI1JGcxJHQxNzgxNTUxNDk0JGo0MyRsMCRoMA.
NARUC-NASEO, 2021b, *Turquoise Cohort Roadmap*, Task Force on Comprehensive Electricity Planning. https://pubs.naruc.org/pub/1528735D-155D-0A36-3128-686829CAE735?_gl=1*1k88r8x*_ga*ODg0OTg5OTU5LjE3NDAyNDgxODM.*_ga_QLH1N3Q1NF*czE3NDg5MDU0MzEkbzUkZzEkdDE3NDg5MDU0MzYkajU1JGwwJGgw.
NARUC-NASEO, 2021c, *Twelve States Announce Action Steps to Plan for Grid of the Future*, Press Release, February 11. https://pubs.naruc.org/pub/B67F456D-155D-0A36-318E-9A9EC01555D6?_gl=1*1a2l8x2*_ga*MjM0NzU0MzAwLjE3NzA2NTUzNDA.*_ga_QLH1N3Q1NF*czE3ODE1NTU4NDckbzI2JGcwJHQxNzgxNTU1ODU3JGo1MCRsMCRoMA.

NARUC-NASEO, ND, “Taskforce Factsheet,” Task Force on Comprehensive Electricity Planning, accessed June 15, 2026. https://pubs.naruc.org/pub/154861E5-155D-0A36-3185-2E12B33288BC?_gl=1*18hgtxr*_ga*MjM0NzU0MzAwLjE3NzA2NTUzNDA.*_ga_QLH1N3Q1NF*czE3ODE1NTEzODUkbzI1JGcxJHQxNzgxNTUxNDk0JGo0MyRsMCRoMA.

NARUC, 2016, *NARUC Manual on Distributed Energy Resources Rate Design and Compensation*, Prepared by the Staff Subcommittee on Rate Design. https://pubs.naruc.org/pub/19FDF48B-AA57-5160-DBA1-BE2E9C2F7EA0?_gl=1*11uqjlr*_ga*MjM0NzU0MzAwLjE3NzA2NTUzNDA.*_ga_QLH1N3Q1NF*czE3NzcwNzkzMDQkbzIkZzAkdDE3NzcwNzkzMDQkajYwJGwwJGgw.

National Laboratory of the Rockies (NLR), ND, “Advanced Hosting Capacity Analysis,” Accessed April 24, 2026. https://www.nrel.gov/solar/market-research-analysis/advanced-hosting-capacity-analysis.html#:~:text=Hosting%20capacity%20is%20the%20amount,added%20to%20the%20distribution%20system.

Nevada Public Utility Commission (NV PUC), 2019, Approved Regulation R029-19, filed October 19 in Docket No. 17-08022. https://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2015_THRU_PRESENT/2017-8/42545.pdf.

New York Department of Public Service (NY DPS), 2021, *Coordinated Grid Planning Process Mid-Cycle Assessment*, Case 20-E-0197. https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={908EBB90-0000-C838-881B-5595C760DDB5}.

New York DPS, 2023, *Order Approving a Coordinated Grid Planning Proces*s, Case 20-E-0197 Issued and Effective August 17. https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7b101C058A-0000-C45D-9CD3-A87E49DF7A99%7d.

NY Public Service Commission (PSC), 2021, *Order Approving Cost-Sharing Mechanism and Making Other Findings*, Cases 20-E-0543 and 19-E-0566, filed July 16.

NV Energy, 2025a, *Joint Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of their joint 2025-2044 integrated resource plan, for the three year Action Plan period 2025-2027, and the Energy Supply Plan period of 2025-2027*, Public Utilities Commission of Nevada.

NV Energy, 2025b, “Distributed Resources Plan Portal,” Accessed April 24, 2026. https://drp.nvenergy.com/.

Oliver, J., 2025, *Taking FlexDemand Operations to the Next Level*, Webinar #5, AESP-California and National AESP, October 23. https://aesp.org/event/ca-chapter-presents-flexdemand-series-part-5-6-integration-and-performance-assessment-approaches/.

Portland General Electric (PGE), 2024, *Distribution System Plan Appendix B. Distribution Planning Process*, https://assets.ctfassets.net/416ywc1laqmd/3vdpaL4ZcQWbcx8o1fkm7p/d793e280a875a89900b50b7eb1b22c4a/Appendix_B._Distribution_planning_process.pdf.

PGE, ND, “Integrated Resource Planning and Clean Energy Planning,” Accessed June 30, 2026. https://portlandgeneral.com/about/who-we-are/resource-planning/combined-cep-and-irp.

Puget Sound Energy (PSE), 2024, *RPAG Meeting 2025 Integrated Resource Plan*, February 13. https://www.cleanenergyplan.pse.com/rpag-meeting-feb.

PSE, 2025, *Resource Planning Advisory Group Meeting 2027 Integrated System Plan*, February 17. https://irp.cdn-website.com/dc0dca78/files/uploaded/2025_0227_RPAGMeeting_Final-f626b91c.pdf.

PSE, 2026, *Resource Planning Advisory Group Meeting 2027 Integrated System Plan*, January 27. https://irp.cdn-website.com/dc0dca78/files/uploaded/2026_0127_RPAG_Meeting_Final.pdf.

Schwartz, L., and N. Mims Frick, 2024, *Integrated Distribution System Planning Overview; Integrated Distribution System Planning 2.0: Planning for Electrification and Distributed Energy Resources*, Lawrence Berkeley National Laboratory, December 11. https://eta-publications.lbl.gov/sites/default/files/2024-12/idsp_overview.pdf.

Schwartz, L., N. Mims Frick, S. Murphy, G. Pereira, G. Relf, J. Shipley, J. Schellenberg, and A. Fernandez, 2024, *State Requirements for Electric Distribution System Planning*, Lawrence Berkeley National Laboratory, December. https://emp.lbl.gov/publications/state-requirements-electric.

Southern California Edison (SCE), 2024, *Moving Toward More Dynamic Markets*, Presentation, CPUC R. 22-11-013 Data Working Group, December 16. https://ucla.app.box.com/s/n4gb89tywv7q1x8smxdrkmkcoq6496pa/file/1722930525103

SCE, 2025, *Grid Needs Assessment and Distribution Upgrade Projects Report of Southern California Edison Company (U 338-E)*, R.21-06-017. https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=584711315.

Stanfield, S., S. Safdi, and S. Baldwin Auck, 2017, *Optimizing the Grid; A Regulator's Guide to Hosting Capacity Analysis for Distributed Energy Resources*, Interstate Renewable Energy Council (IREC) and Shute Mihaly & Weinberg, LLP, December. https://irecusa.org/wp-content/uploads/2021/07/IREC-Optimizing-the-Grid-2017-1.pdfhttps://irecusa.org/wp-content/uploads/2021/07/IREC-Optimizing-the-Grid-2017-1.pdf.

State and Local Energy Efficiency Action Network (SEE Action), 2020, *Determining Utility System Value of Demand Flexibility from Grid-Interactive Efficient Buildings*, prepared by: Tom Eckman, Lisa Schwartz, and Greg Leventis, Lawrence Berkeley National Laboratory. https://www.energy.gov/eere/buildings/articles/see-action-determining-utility-system-value-demand-flexibility-gridhttps://www.energy.gov/eere/buildings/articles/see-action-determining-utility-system-value-demand-flexibility-grid

Stenclik, D., and S. Hostetter, 2025, *Gaps, Barriers, and Solutions to Demand Response Participation in Wholesale Markets*, January, Energy Systems Integration Group. https://www.esig.energy/demand-response-in-wholesale-markets.

Steyer, T., 2025, LinkedIn post summarizing a panel discussion with Pedro Pizarro, CEO of Southern California Edison and Kim Zou of Sightline Climate: "Right now, most major utilities across the US are running at only 30–35% utilization." October 7.

Telos Energy, report to the Illinois Commerce Commission on resource accreditation in PJM and MISO, April 2026.

Terwilliger, H., A. Northagen, and T. Dornfeld. 2024. *Staff Briefing Papers*. Docket No. E111/M-23-420; E015/M-23-258; E017/M-23-380; E002/M-23-452. Filed June 20, 2024. Available at: https://mn.gov/puc/edockets/.

The Electricity Forum, 2025, "What is the Load Factor in Electrical?," accessed Oct. 14, 2025. https://electricityforum.com/iep/power-quality/what-is-the-load-factor-in-electricalhttps://electricityforum.com/iep/power-quality/what-is-the-load-factor-in-electrical.

U.S. Department of Energy (DOE), 2020, *Modern Distribution Grid: Strategy and Implementation Guidebook*. https://gridarchitecture.pnnl.gov/media/ModernDistribution-Grid_Volume_IV_v1_0_draft.pdf.

Wilson, R., and B. Biewald, 2013, *Best Practices in Electric Utility Integrated Resource Planning*, Regulatory Assistance Project (RAP), June. https://www.synapse-energy.com/sites/default/files/SynapseReport.2013-06.RAP_.Best-Practices-in-IRP.13-038.pdf.

Wiser, R. H., G. Barbose, P. Cappers, W. Gorman, S. Murphy, L. C. Schwartz, N. Mims Frick, G. Pereira, A. Mallet Dias, J. Chuang, and V. Srinivasan, 2026a, *Electric Utility Distribution Costs: Scoping Study on Trends, Drivers, and Possible Response Strategies*, Lawrence Berkeley National Laboratory, May. https://emp.lbl.gov/publications/electric-utility-distribution-costs.

Wiser, R., G. Barbose, P. Cappers, J. Deason, S. Forrester, W. Gorman, E. O'Shaughnessy, R. Hledik, L. Lam, and A. Yan, 2026b, *Retail Electricity Price Trends and Drivers: Data Update–2026 Edition*, Lawrence Berkeley National Laboratory and the Brattle Group, October. https://emp.lbl.gov/publications/retail-electricity-price-trends-and.

Xcel Energy, 2025, *Xcel Energy to meet Minnesota's energy needs with first-in-the-nation distributed capacity procurement,"* Press Release, October 6. https://newsroom.xcelenergy.com/news/xcel-energy-to-meet-minnesotas-energy-needs-with-first-in-the-nation-distributed-capacity-procurement#:~:text=Xcel%20Energy%20to%20meet%20Minnesota's,important%20part%20of%20that%20strategy.

Yu, R. and P. De Martini, 2024, *Flexible DER & EV Connections*, U.S. Department of Energy, July. https://www.energy.gov/sites/default/files/2024-08/Flexible%20DER%20%20EV%20Connections%20July%202024.pdf.

Appendix A. Details on the Distribution System Planning Process

The DSP process is increasing in sophistication, enabling better integration with IRP. Modern DSP employs a suite of analytical methods, including the following.

- **Load forecasting:** Like IRP, forecasting is the foundation of the DSP process. Historically, utilities forecasted systemwide peak demand, or seasonal peak demand. Increasingly, utilities are incorporating more spatially and temporally granular forecasts, down to the substation or feeder levels on an hourly (8760) basis, to better understand localized risks and upgrade needs.
- **GER forecasting:** GER forecasting assesses when and where GER adoption may occur, producing estimates of installed capacity and generation and load and dispatch profiles. GER forecasts are important inputs to other components of the DSP. The GER and load forecasts combined create a net load forecast.
- **Power flow studies:** These studies assess voltage profiles, thermal loading, reactive power flows, and unbalanced loading under different grid conditions and futures. Outputs include forecasted voltage and power quality data. Power flow studies are fundamental for hosting capacity analyses and inform grid investment needs.[108]
- **Hosting capacity analyses (HCA):** Derived from power flow analysis, HCA evaluates how much additional GER capacity[109] can be integrated at specific points on the distribution system without negative impacts to power quality or reliability, assuming no changes to the distribution system. This helps to identify the potential location and causes of distribution system constraints and associated modifications such as grid upgrades or operational changes.
- **Resilience and reliability analyses:** Utilities assess the performance of the distribution system across multiple reliability indices such as the System and Customer Average Interruption Duration and Frequency Indices (SAIDI and SAIFI, CAIDI, and CAIFI).[110]
- **NWA analyses:** Utilities assess whether storage or portfolios of GERs can meet certain identified future distribution system needs, such as to provide load reduction, reduce power interruptions, or address voltage issues, in a more cost-effective manner compared to traditional infrastructure.
- **Locational value analyses:** HCA can be used to determine the locational benefits of GERs at specific locations on the distribution system. The analysis can help identify high-value locations for GERs, assist in prioritizing NWAs and other investments, and inform GER compensation and incentive strategies.[111]

---

[108] Homer et al., 2020.
[109] Some utilities consider hosting capacity for electric vehicle charging and other loads. The granularity and usefulness of HCA information may vary by type of load (e.g., large loads connected at primary distribution voltage) or GERs assessed. The U.S. DOE tracks HCA information at https://www.energy.gov/cmei/vehicles/us-atlas-electric-distribution-system-hosting-capacity-maps.
[110] Schwartz et al., 2024.
[111] Homer et al., 2020.

Distribution Capacity planning

Distribution capacity planning primarily involves planning for customer load, GER growth, and spare capacity to ensure operational flexibility.[112] The process aims to identify needed upgrades or new equipment where system components no longer meet or are forecasted to exceed (fail) planning standards.

Utilities typically "plan to peak," meaning they design distribution system assets to reliably operate during forecasted peak demand[113] expected to occur during the planning period. The analysis includes the coincident net effect of any export power flows from distribution-level generation. The analysis is based on disaggregated forecasts for loads and GER, weather data, and scenarios (discussed above).

Distribution capacity planning is fundamentally an engineering exercise to ensure substations and circuits can deliver power within thermal, voltage, and protection limits across normal and contingency conditions over a 5- to 10-year planning horizon. The process includes several engineering analyses:[114]

- **Thermal Capability**[115] - Assess the ability of conductors, cables, transformers, voltage regulators, breakers, and other equipment to carry projected loading within design standards for normal and emergency ratings, contingency margins, loading durations, and weather conditions
- **Voltage/Power Quality** - Assess whether steady-state voltages and other service quality operating criteria, such as acceptable service voltage levels, flicker, power factor, and harmonic distortion, that may be affected by customer machinery and generation inverters remain within required standards[116]
- **Contingency Transfer Capability** - Assess the capacity of the distribution network to enable switching plans and back-ties without violating thermal or voltage limits during planned and unplanned events
- **Protection and Safety** - Assess fault-current duties within transformer, conductor, and other distribution equipment ratings; coordinate relay and fuse protection with GER adoption, including bidirectional flows; and determine proper protection settings for contingency grid reconfigurations
- **Deliverability Paths** - Determine unconstrained and constrained distribution areas, substation transformers, and feeders to interconnect and transport injected energy from

[112] Operational flexibility allows the utility to move load on the distribution system when needed for planned maintenance and reliability during unplanned outages.
[113] Often caused by extreme temperatures. Utilities typically use a probability-based metric in power distribution to ensure grid reliability. For example, a P90 forecast indicates a 10% chance that actual peak demand will exceed the forecast.
[114] Hawaiian Electric, 2020.
[115] Electric current flowing through a distribution network generates heat. The higher the current (and associated power), the greater the heat generated. "Ampacity" refers to the safe level of current-carrying thermal capability. It is a calculated, continuous rating of the conductors' ability to operate safely, even on the hottest day, without failing.
[116] The national standard, ANSI C84.1-2020, establishes nominal voltage ratings and operating tolerances for 60 Hz electric power systems above 100 Volts (V), up to a maximum system voltage of 1,200 kV. For example, for a nominal operating voltage of 120 V, the acceptable operating voltage range is 114 V–126 V.

distributed generation and batteries (both front of the meter and behind the meter) to desired locations in the bulk system[117]

The outputs of DSP include technical metrics, documentation of analyses and decision making, including investment plans. Documentation includes hosting capacity maps, reliability indices, system upgrade requirements, locational value estimates, and NWA assessments. Increasingly, these outputs are shared publicly through filings, data portals, and stakeholder workshops. Many states now require utilities to demonstrate how they engage stakeholders such as utility consumer advocates in shaping planning assumptions and evaluating alternatives.[118]

DSP Procurements

DSP has historically focused only on procuring utility-owned equipment to meet engineering-based needs. However, DSP increasingly evaluates alternatives to traditional distribution infrastructure investments. Utilities may use competitive solicitations to determine whether NWAs are cost-effective, as well as geotargeted utility programs and rate design (Schwartz et al., 2024).

[117] This may involve hosting capacity analysis and additional deliverability analysis to assess impacts of reverse power flow.
[118] Schwartz et al., 2024.

Appendix B. Key Resources

- Best Practices in Integrated Resource Planning
- Bridging the Gap on Data and Analysis for Distribution System Planning: Information That Utilities Can Provide Regulators, State Energy Offices and Other Stakeholders
- Changing Considerations for Integrated Resource Planning (IRPs) for Systems in Transition
- Charging Ahead: Grid Planning for Vehicle Electrification
- Distributed Energy Resources and Electric Vehicle Adoption
- Distribution Capacity Expansion Planning: Current Practice, Opportunities, and Decision Support
- Distribution Grid Orchestration
- Distribution Planning with Local Resources: Integration and Valuation
- Distribution System Evolution
- Distribution System Scenario Planning Case Study and Guidance on Considering Scenarios and Investment Approaches in Distribution Planning
- Evolving Paradigms in State-Level Integrated Resource Planning
- Flexible DER & EV Connections
- Gaps, Barriers, and Solutions to Demand Response Participation in Wholesale Markets
- Grid Planning for Building Electrification
- Integrated Distribution Planning: A Path Forward
- Integrated Resilient Distribution Planning
- Integrated System Planning Guidebooks
- Integrated System Planning: Holistic Planning for the Energy Transition
- NARUC/NASEO comprehensive electricity planning resources
- Reimagining Resource Planning
- Resource Planning and Regulatory Considerations
- Sourcing Distributed Energy Resources for Distribution Grid Services
- State regulatory opportunities to advance Distributed Energy Resource Aggregations in Wholesale Markets
- State Requirements for Distribution System Planning
- Summary of Electric Distribution System Analyses with a Focus on DERs

Appendix C. List of Organizations Interviewed

Organization	Type
California Public Utilities Commission	PUC
Camus Energy	Industry
Duke Energy	Utility
E3	Industry
Georgia Public Service Commission	PUC
Green Mountain Power	Utility
Hawaiian Electric Company	Utility
Idaho Power	Utility
Indiana Utility Regulatory Commission	PUC
Maryland Public Service Commission	PUC
Michigan Public Service Commission	PUC
Minnesota Public Utilities Commission	PUC
Missouri Public Utilities Commission	PUC
New York Department of Public Service	PUC
Salt River Project	Utility
Telos Energy	Industry
University of Vermont	Industry
Vermont Electric Coop	Utility
Virginia State Corporation Commission	PUC