July 2026

EMERALD ROADMAP

NARUC-NASEO INITIATIVE: COMPREHENSIVE ELECTRICITY PLANNING IN AN ERA OF LOAD GROWTH

NARUC
National Association of
Regulatory Utility Commissioners

NASEO
National Association of
State Energy Officials

Table of Contents

Planning Categories

- Establish expectations & assumptions
- Develop scenarios
- Develop forecasts
- Identify system needs
- Identify solutions
- Evaluate solutions
- Finalize plan

About Emerald: A Fictional, Representative State

Regulatory	
Our state's investor-owned utilities	**do not own generation assets**
Market	
Our state is located	**within an RTO/ISO market**
Planning Processes	
Our state is seeking to align	**distribution planning processes with bulk power decisions**

Introduction

This roadmap document describes a vision for best-in-class comprehensive electricity planning, shown in a flowchart and accompanying descriptive text. This idealized planning process is viewed from the state perspective, specifically a collaboration between the State Public Utility Commission (PUC) and State Energy Office. The roadmap was the result of robust engagement with a cohort of National Association of Regulatory Utility Commissioners (NARUC) and National Association of State Energy Officials (NASEO) members drawn from 24 states and Washington, DC who joined the **NARUC-NASEO Initiative: Comprehensive Electricity Planning in an Era of Load Growth**. Initiative members attended virtual and in-person workshops to collaborate in articulating their priorities for better aligning distribution, resource, and transmission planning.

This roadmap includes:

- A flowchart of the entire integrated or aligned planning process
- Brief descriptions and explanations of each section of the flowchart
- A color key (above left) outlining each box in the flowchart—to allow for comparison with other cohort roadmaps. The colors align with seven generalized procedural and analytical planning steps that typically characterize electricity system planning processes.

While these practices may not reflect current planning across all jurisdictions, the roadmap describes what could be implemented over time as utility capabilities, data and analytical sources, resource availability, and regulatory frameworks evolve.

The roadmap is intended to support states considering taking actions to increase the alignment of their own electricity system planning processes by providing:

- A high-level understanding of the sequence of steps included in an electricity planning process
- Descriptions of ideal information flows and coordination points represented in the vision, as articulated by NARUC and NASEO members
- Starting points for all states, particularly those with similar characteristics to the Emerald cohort

Development of the Flowchart and Roadmap

An original set of five comprehensive electricity planning flowcharts and roadmaps were developed by a group of Commissioners and State Energy Office leaders from 15 states in 2018 to 2021. These resources were used by numerous states as starting points for enhancing their electricity planning processes. Given significant load growth projections and technological changes in the planning landscape since then, in 2025 NARUC and NASEO launched an initiative to refresh the original roadmaps to support state decision makers facing today's evolving challenges.

Through virtual and in-person collaborations over more than a year, members from 24 states and Washington, DC gathered to identify upgrades that would make the roadmaps relevant and actionable in an era of load growth. Researchers from the U.S. Department of Energy's (DOE) national laboratories, industry leaders, and subject-matter experts also provided input to ensure the new flowcharts and roadmaps are accurate, practical, and reflective of current and emerging industry best practices.

How to Use the Roadmap

It is important to recognize what the flowchart and the roadmap do and do not address. These materials describe the key activities, milestones, and regulatory actions that comprise the planning processes, focusing on their substance, but without trying to place them on a timeline or calendar, and without indicating which entities or actors are responsible for which activities (except where a regulatory decision is obviously the role of a PUC). In other words, the flowchart and accompanying roadmap focus only on the "what"—the procedural and analytical steps that make up each planning process and the actions proposed for coordinating or integrating the processes.

While the flowchart is presented visually from left to right, in practice many steps are iterative, overlapping, and can occur in parallel. The authors have attempted to indicate where these iterations are particularly important, but any practical implementation of the flowchart will surely result in additional iteration. Accordingly, the flowchart does not need to be used as a whole: states will adapt pieces and parts of the idealized planning process that best suit their policy and regulatory contexts.

Additional Resources

During development of the roadmap, the authors identified where existing guidance, resources, or examples could support operationalizing the major process steps described in the roadmap. These references will be accessible on a public website that is searchable and can be filtered by planning process building blocks. In some cases, gaps in available resources may signal areas where new tools and approaches are needed to better align planning processes.

Flowchart Key

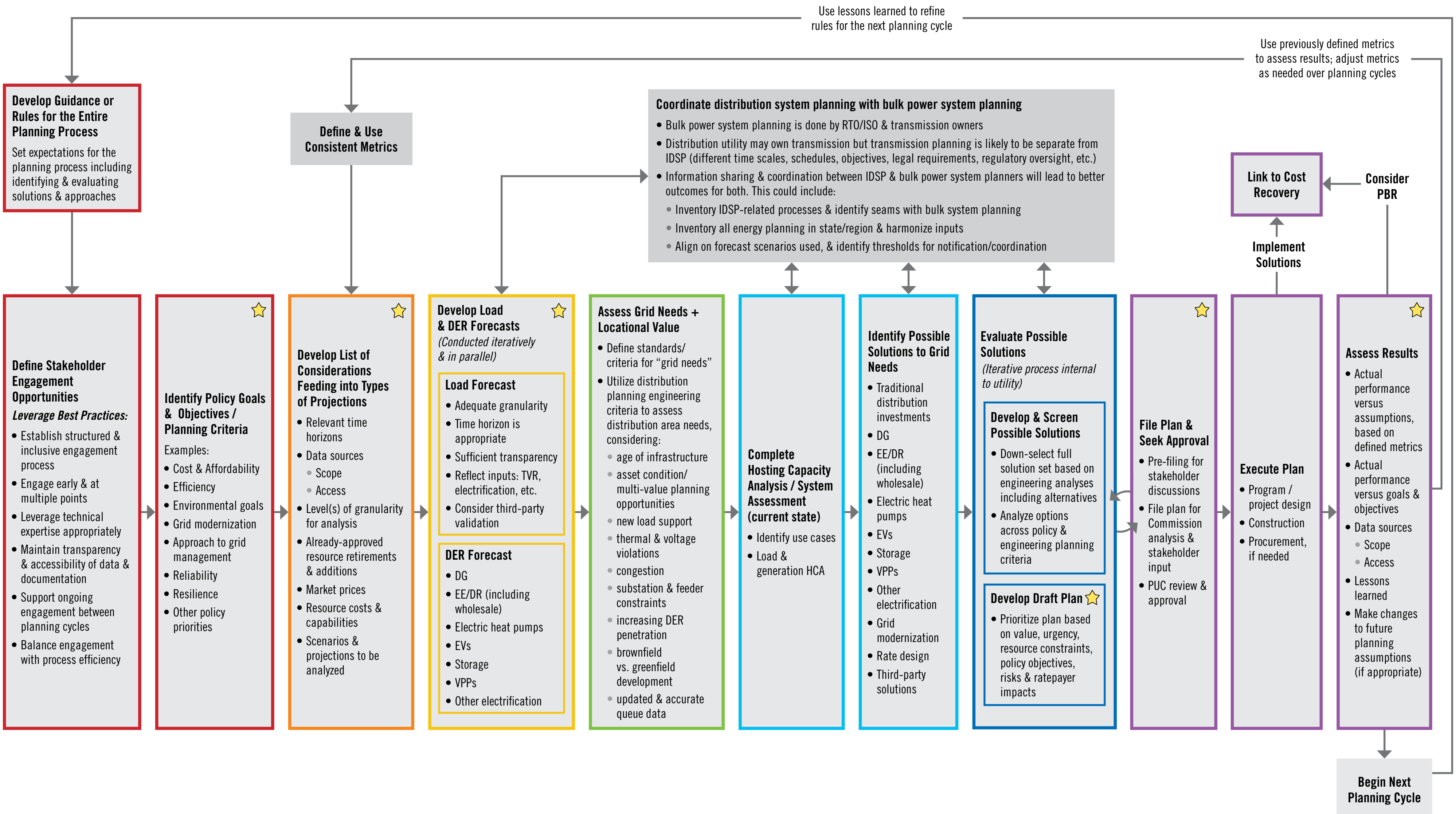
Planning Categories

- Establish expectations & assumptions
- Develop scenarios
- Develop forecasts
- Identify system needs
- Identify solutions
- Evaluate solutions
- Finalize plan
- Stakeholder engagement
- Information flows
- Iteration step (curved arrows)

Acronyms

DER: Distributed Energy Resource
DG: Distribution Generation
DR: Demand Response
EE: Energy Efficiency
EVs: Electric Vehicles
HCA: Hosting Capacity Analysis
IDSP: Integrated Distribution System Planning
IRP: Integrated Resource Planning
ISO: Independent System Operator
PBR: Performance-based Regulation
PUC: Public Utilities Commission
RTO: Regional Transmission Organization
VPP: Virtual Power Plant
TVR: Time Varying Rates

Emerald Flowchart



Emerald Flowchart Description

The Emerald flowchart outlines what an ideal comprehensive planning process could look like for a hypothetical state where utilities do not own generation and are within a Regional Transmission Organization (RTO) or Independent System Operator (ISO) market, often called a restructured state.

The Emerald flowchart includes the process steps and relationships for integrated distribution system planning (IDSP) conducted by a distribution utility and connections to bulk power system (BPS) planning performed by an RTO or ISO. Each section of the Emerald flowchart contains specific process steps with information flows, as indicated by colored boxes and arrows.

The present roadmap was created to be a companion to the flowchart and provide a more detailed description of the various elements of comprehensive electricity planning and points of coordination across the planning scopes.

Together, the flowchart and roadmap describe a comprehensive set of planning activities and coordination points that better align distribution planning processes with BPS decisions. These steps are explained in more detail on the following pages: each section focuses on one portion of the flowchart.

The Emerald flowchart includes several design features that capture best practices for integrated planning. These design features include:

- **Transparency in distribution planning:** In some ways the entire process envisioned in this roadmap is innovative, compared to traditional distribution planning, because it introduces a measure of transparency on how decisions are made about investments in the distribution system. Transparency is balanced with data availability, system compatibility, cybersecurity, and privacy considerations, which may limit the granularity or frequency of information sharing.
- **Potential for multiple stakeholder engagement opportunities:** Stakeholders may be engaged at multiple points in the process, not merely at the end of the process when a draft plan is filed by the utility at the Commission. Ideally, the Commission and other relevant agencies decide at the outset of the planning process how stakeholders will be invited to participate. Stakeholders may be involved at multiple points throughout the planning process, where their input and engagement are most needed to support good planning outcomes. While stakeholder engagement is valuable throughout the process, technical planning, engineering standards, and operational decisions remain utility-led functions, given reliability obligations and system expertise. In all cases, stakeholder engagement is conducted in a manner that is consistent with any legislative mandates and leverages state-specific procedures and best practices.

Enabling Conditions

Cohort participants discussed two underpinning issues that need to be considered if a state intends to implement the comprehensive planning process described throughout the roadmap.

- **Access to data and information:** To successfully complete a comprehensive electricity planning process, decision makers and stakeholders will need data and information from the relevant utilities throughout the process. Acquiring information in a timely and transparent manner requires coordinated data sharing across multiple organizations. For example, early in the distribution system planning process, planners will need information on distribution circuit-level hosting capacity to target distributed energy resource (DER) development to locations with available capacity. Later in the process, third-party providers of non-wires solutions (NWS) will need information on identified system needs and proposed upgrades to respond to utility solicitations or requests for proposals (RFPs). NARUC's Grid Data Sharing Framework can be a starting point for states that do not have existing data sharing agreements in place.
- **Up-to-date methodologies for evaluating new technologies:** New technologies often lack a track record that can give grid operators confidence in their performance capabilities and reliability; additionally, their costs can vary significantly from one planning cycle to the next. These factors challenge the ability to perform traditional benefit-cost analyses to determine preferred solutions and may lead to the rejection of new technologies in favor of familiar solutions. Comprehensive electricity planning requires supplementary processes for obtaining reliable, current information on non-traditional technology options that can offer potential solutions to the system needs identified in the planning processes.

- **Flexibility:** At several key steps, the flowchart identifies a list of options or things to consider that allows for flexible interpretation and flexible implementation by any state that wants to adapt the process to local norms.
- **Links between IDSP process and BPS planning:** Although this flowchart is for restructured utilities in an RTO, the process notes multiple steps where coordination between IDSP planners and BPS planners (principally at the RTO) needs to happen to achieve better results from both planning processes.
- **Breadth of potential solutions:** The flowchart draws attention to the range of possible solutions to distribution needs, including wires, non-wires, third-party solutions, and rate design. It also notes some criteria that might be used to screen and compare potential solutions.
- **Links to cost-recovery:** The flowchart notes the connection between implementation solutions and cost recovery. The flowchart also includes an assessment step as part of implementation, and notes that the results achieved by the plan may be linked to cost recovery, for example, through a performance-based regulation (PBR) mechanism.
- **Recognition of data, modeling, and system constraints:** Comprehensive planning depends on the availability of compatible data systems, modeling capabilities, and internal coordination across utility departments, which may limit the pace and scope of integration.

Develop Guidance or Rules for the Entire Process

As a first step, the PUC **establishes guidance or rules** for the distribution system planning process to be used by all affected utilities. These rules define expectations for how planning will be conducted, including how system needs are identified, how solutions are evaluated, and how plans are developed and reviewed. Variations in the process may be appropriate for different types of utilities and can be specified within the guidance or rules, but the overall objective is to promote a clear, consistent, and transparent approach across utilities.

When developing guidance or rules for the first time, the Commission may engage utilities and other stakeholders in a series of educational meetings to build a common understanding of relevant terminology, planning practices, and emerging issues. These discussions may include a review of previous planning approaches and outcomes, as well as the development of a problem statement that defines the purpose and scope of the IDSP process.

The guidance or rules may also establish expectations for:

- The structure and contents of IDSP filings
- The analytical methods and assumptions used in planning
- The level of transparency and data access provided to stakeholders
- The timing and frequency of planning cycles

This step provides the foundation for all subsequent planning activities and ensures alignment between regulatory expectations, utility practices, and stakeholder engagement.

Define Stakeholder Engagement Opportunities

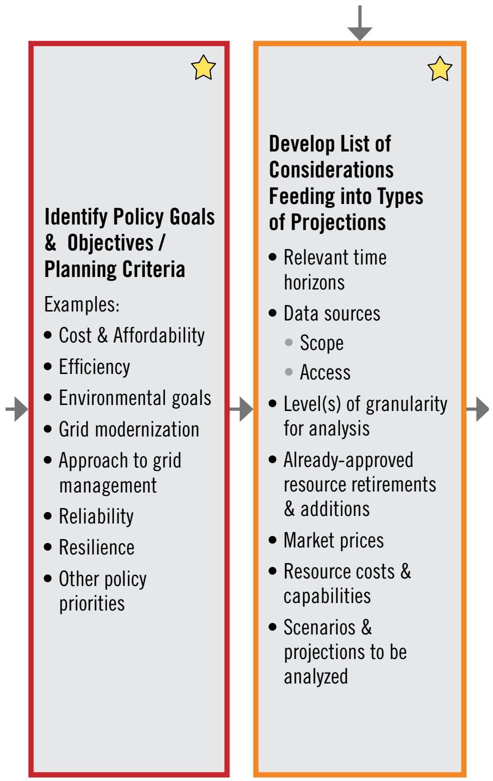
As part of establishing the planning process, the Commission defines how and when stakeholders will be engaged throughout the IDSP cycle. A structured approach to stakeholder engagement can improve transparency, strengthen the quality of inputs and assumptions, and build confidence in planning outcomes.

Stakeholder engagement processes are typically designed to be **inclusive, transparent, and iterative**, while maintaining a balance between meaningful participation and overall process efficiency. Engagement may include utilities, regulators, State Energy Offices, customers, third-party providers, and other interested parties.

Best practices for stakeholder engagement include:

- Establishing a **structured and inclusive engagement process**, such as advisory groups or working groups
- Providing opportunities for input **early and at multiple points** in the planning process, rather than only at the end
- Leveraging **technical expertise** from stakeholders to inform specific areas such as Distributed Energy Resource (DER) adoption, electrification, or market participation
- Maintaining **transparency and accessibility** of key assumptions, data, and methodologies, as appropriate
- Supporting **ongoing engagement between planning cycles** to refine methods and address emerging issues
- Balancing stakeholder input with the need for **efficient and timely decision-making**

Stakeholder input may be used to inform planning assumptions, identify emerging trends, and provide feedback on draft plans. However, utilities retain responsibility for conducting technical analyses and maintaining system reliability, and stakeholder engagement is designed to complement—not replace—utility-led planning activities.



Data acquisition and management are cross-cutting functions throughout the planning process, beginning with the definition of assumptions and inputs and continuing through forecasting, system assessment, and evaluation.

Identify Policy Goals, Objectives, Planning Criteria and Considerations

With stakeholder engagement processes defined, the Commission then identifies **policy goals, objectives, and planning criteria** that guide all subsequent planning activities. These can include, for example, cost and affordability, efficiency, environmental goals, grid modernization, approach to grid management, reliability, resilience, and other policy priorities. Goals and objectives may originate from legislation or from previously established regulations, orders, or corporate commitments made by utilities. Additional goals and objectives may be developed as part of the planning process, potentially with input from stakeholders, if directed in the Commission's guidance or rules.

Metrics for achieving the specified goals are defined and will be used consistently throughout the planning process and across all affected utilities. For example, standard reliability metrics are defined and consistently used to assess progress toward reliability goals.

Planning criteria can translate these high-level objectives into actionable thresholds to be used in later stages of the planning process. These criteria define the conditions under which system investments will be triggered and provide a consistent basis for identifying and evaluating grid needs.

Once goals, objectives, and planning criteria are established, **important factors will be identified that will be considered** when developing planning assumptions that feed into different types of projections. Guidance includes specifications related to time horizons for forecasting and investment planning; the expected level of granularity for the analysis (spatially and temporally); the types of scenarios and projects to be analyzed; acceptable sources of data for model inputs and how those data may, or may not, be accessed by others; information about already-approved resource retirements and additions; current and projected market prices; and resource costs and capabilities.

When considering data sources and data access, the transparency of data and the uses of data are considered to inform the planning process and to enable evaluation and assessment of outcomes as the plan is implemented. Care is also taken to ensure that the planning process is designed to be completed efficiently, allowing utilities to make both routine and non-routine investments necessary for reliable and cost-efficient service.

Develop Load & DER Forecasts

Forecasting is conducted for both load and DERs and is ideally performed **iteratively and in parallel**, with information shared between forecasting processes. To support meaningful analysis, these forecasts should be developed using consistent or aligned underlying assumptions, including factors such as population and economic growth, climate conditions, and policy drivers. The **(DER) forecast** includes energy efficiency (EE) and demand response (DR), including EE and DR resources that bid directly into the wholesale market, as well as distributed generation (DG), storage, electric vehicles (EVs), and electrification measures. The **load forecast** incorporates the impacts of the forecasted DERs and time-varying rates (TVR) with the projected end-use energy demand of customers. It is important that these forecasts have sufficient granularity, a time horizon that is sufficiently long, and sufficient transparency to enable an accurate assessment of grid needs (in the next step of the planning process).

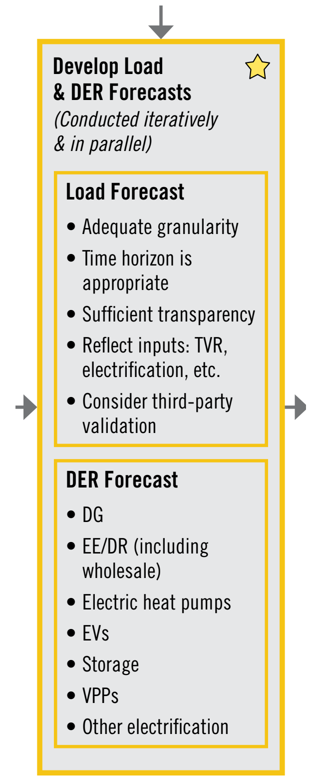
In practice, load and DER forecasts may be developed by different teams or tools, which can limit full integration. As a result, coordination across forecasting processes is critical, even where full integration is not feasible. Forecasts should also consider a range of uncertainties, including policy-driven changes, electrification (e.g., EVs and heating), and large load growth (e.g., data centers), as well as interconnection requests, which can provide useful signals but may not fully reflect realized future demand.

Forecasting includes data standardization and scenario analysis to capture policy and market uncertainties. Several types of projections may be developed for both DER and load forecasts, including short- and long-term projections, current and planned resources, location-specific forecasts, and projections that include resources cleared in the wholesale market. Forecasts may also be refined based on system constraints identified in hosting capacity analysis and system assessments, and creating feedback loops across planning steps.

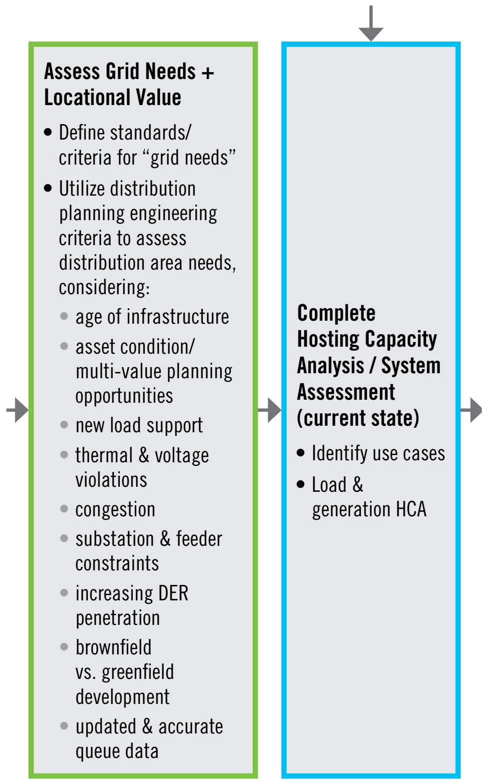
Each jurisdiction will decide for itself which entity or entities will be responsible for developing the load forecast, but in all cases the forecast is developed with coordinated input from distribution system planners and bulk system planners (principally at the RTO/ISO or with transmission owners). At a minimum, distribution system planners would provide a net load forecast to the BPS planners that includes the impacts of DERs. Or, at the request of the bulk system planners, separate DER forecasts and gross load forecasts could be provided. In turn, bulk system planners would provide information to distribution system planners about DERs bidding directly into the wholesale market.

Projected policy impacts could influence the DER forecast and load forecast. These forecasts account for the impact of state policies that require, encourage, or reward customers for deploying DER or managing load.

States have flexibility in whether or how to involve **stakeholders** – which could include State Energy Office staff, PUC staff, RTO/ISO representatives, utilities, and other stakeholders –



This is the first of several instances in the planning process where information sharing and coordination between distribution planners and bulk power planners occurs, improving outcomes for both.



In practice, system needs may be identified across multiple departments within a utility (e.g., planning, operations, and asset management) and may involve different methods and assumptions.

in the forecasting process. Stakeholders may provide useful signals about the likelihood of future DER and load scenarios that may affect forecasts. Stakeholder input may help utilities incorporate new or challenging elements into forecasting where utilities may have less experience (e.g., heating electrification or electric vehicles). Working groups may be an effective way to engage stakeholders at this stage in the process.

Assess Grid Needs + Locational Value

After defining the criteria or standards for **grid needs**, system needs are assessed through a combination of the application of distribution planning engineering criteria, system assessment, and hosting capacity analysis (HCA).

Planning criteria established earlier in the process are applied to determine when and where system upgrades or investments are required. System needs may be identified based on a range of factors, including:

- Age and condition of existing infrastructure
- Opportunities for multi-value investments (e.g., addressing both capacity and asset condition needs)
- New load growth and electrification needs
- Thermal and voltage violations
- Congestion and substation or feeder constraints
- Increasing DER penetration and interconnection queue data
- Differences in development patterns (e.g., brownfield vs. greenfield development)

These needs may be categorized as capacity-driven needs (e.g., thermal or voltage constraints), asset condition and replacement needs, reliability and resilience needs, and enabling needs for DER integration and electrification.

Using the same data, the locational value of DERs can also be assessed at a granular geographic level, although implementation of locational value assessment at scale remains limited in many jurisdictions and may rely on proxy or partial approaches.

The system assessment step should also consider any needs relating to the condition of existing grid assets. Options exist for this kind of routine asset management. Some expenses—particularly those that are relatively inexpensive and require immediate action to maintain or restore reliability—may be managed outside of the IDSP process (e.g., as an asset management program with a defined annual budget).

HCA is then conducted as part of this broader assessment of the current state of the distribution system, helping to characterize both capabilities and limitations at a granular level. Because there can be multiple types of HCA and multiple possible use cases, the planning use case should be clearly defined, potentially with input from stakeholders, to ensure that the analysis is applied effectively. HCA is one of several analytical tools used in this step and does not replace detailed interconnection studies or other engineering assessments.

In addition to HCA, utilities apply distribution planning engineering criteria to assess system conditions and identify areas of need. These criteria are used to evaluate system performance and constraints across the distribution network.

The results of the system assessment, the HCA, and the DER and load forecasts are combined to identify any future distribution **grid needs**. Planning criteria established earlier in the process are applied to determine when and where system upgrades or investments are required. By incorporating hosting capacity analysis in the identification of system needs, the planning process can consider not only what is needed to accommodate future load but also what is needed to enable the integration of DERs at sufficient levels to meet the objectives and goals of the jurisdiction.

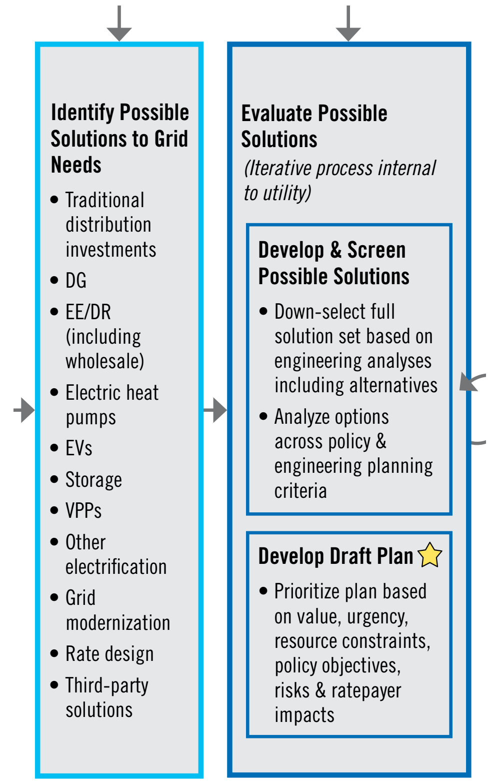
Identify & Evaluate Possible Solutions

After needs are identified, the next step is to **identify possible solutions to grid needs**. Rather than evaluating solutions in isolation, planners consider a portfolio of potential solutions to address system needs.

A comprehensive range of potential solutions to distribution system needs are considered holistically, including "wires" solutions (i.e., traditional infrastructure investments such as substations, transformers, wires, etc.), non-wires solutions (e.g., targeted deployments of DERs that defer or avoid the need for a wires investment), utility operational changes or maintenance activities, third-party or customer-based solutions, and changes in rate design.

Most often, not all system needs can be addressed through a singular solution. A combination of solutions—including traditional infrastructure investments and non-wires solutions—may be required to maintain a reliable and resilient grid. In restructured states, utilities are often limited in the types of investments they are authorized to make (e.g., they are precluded from owning generation assets) and may be hesitant to allow third parties to own and operate assets on the distribution system. Stakeholder input may be invited as part of the solution identification.

Evaluating possible solutions is typically an iterative process internal to the utility, consisting of both screening of potential solutions and the development of a prioritized draft plan. In the initial stage, planners develop and screen possible solutions, including both traditional infrastructure investments and alternatives. This consideration may involve internal justification of projects, engineering analysis of alternatives, and the down-selection of a full set of potential solutions based on technical feasibility and alignment with planning criteria.



The screening and evaluation step requires clearly identified criteria and may involve an independent technical review to confirm that proposed solutions actually satisfy the needs identified. States can develop unique approaches to screening criteria to identify solutions that meet their circumstances.

Evaluation criteria are used to **screen and compare potential solutions** on a fair and equal basis. Planners determine whether each possible solution achieves the established policy goals and analyze the impact of the solution on rates or ratepayers. Evaluation criteria are informed by the planning criteria and objectives established earlier in the process and may include considerations such as cost, reliability, resilience, and alignment with policy priorities.

For example, if a jurisdiction has adopted specific goals for one of the standard reliability metrics (SAIDI or SAIFI), each potential solution would be screened to see how well it addresses those goals. Or, if a jurisdiction has a policy goal relating to electric vehicles, the screening process would evaluate whether each solution is consistent or inconsistent with achieving that goal.

If there are differences in the certainty that a given solution will perform as expected, or performance is dependent or contingent on other actions outside the control of the planners, non-performance risk can be factored into the evaluation criteria. Evaluation may also include scenario analysis and sensitivity testing to assess how solutions perform under different future conditions. Ratepayer impacts are most often evaluated based on the present value revenue requirement of each solution, often with separate values developed for different planning scenarios or to test the sensitivity of results to key data inputs (e.g., technology costs).

In practice, the level of analysis may vary depending on the type and scale of the investment; not all projects require the same level of detailed cost-benefit analysis.
The evaluation criteria may be jurisdiction specific. NASEO's National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources can be a starting point for states that do not have jurisdiction-specific evaluation criteria already established.

Considerations related to grid modernization are incorporated throughout the planning process rather than treated as a separate step. Investments in advanced technologies (e.g., advanced metering infrastructure, advanced distribution management systems, or distributed energy resource management systems), as well as upgrades to existing grid infrastructure and asset replacement or hardening efforts, may enable new types of solutions, improve system visibility, and support the integration of DERs and electrification. These investments may be identified and evaluated as part of the broader portfolio of solutions, or may be advanced through parallel regulatory processes. In all cases, coordination and information sharing across related planning efforts can help avoid duplication, improve efficiency, and maximize overall system value.

Following screening and evaluation, planners **develop a draft plan** that prioritizes solutions based on value, urgency, resource constraints, policy objectives, and risk. This step may include assessing ratepayer impacts, conducting risk assessments, and incorporating strategic or leadership-level considerations. Solution selection at this stage may also influence broader portfolio or asset management decision-making, and vice versa.

Throughout the assessment of system needs and the identification and evaluation of possible solutions, coordination with BPS planning and consideration of grid modernization opportunities takes place.

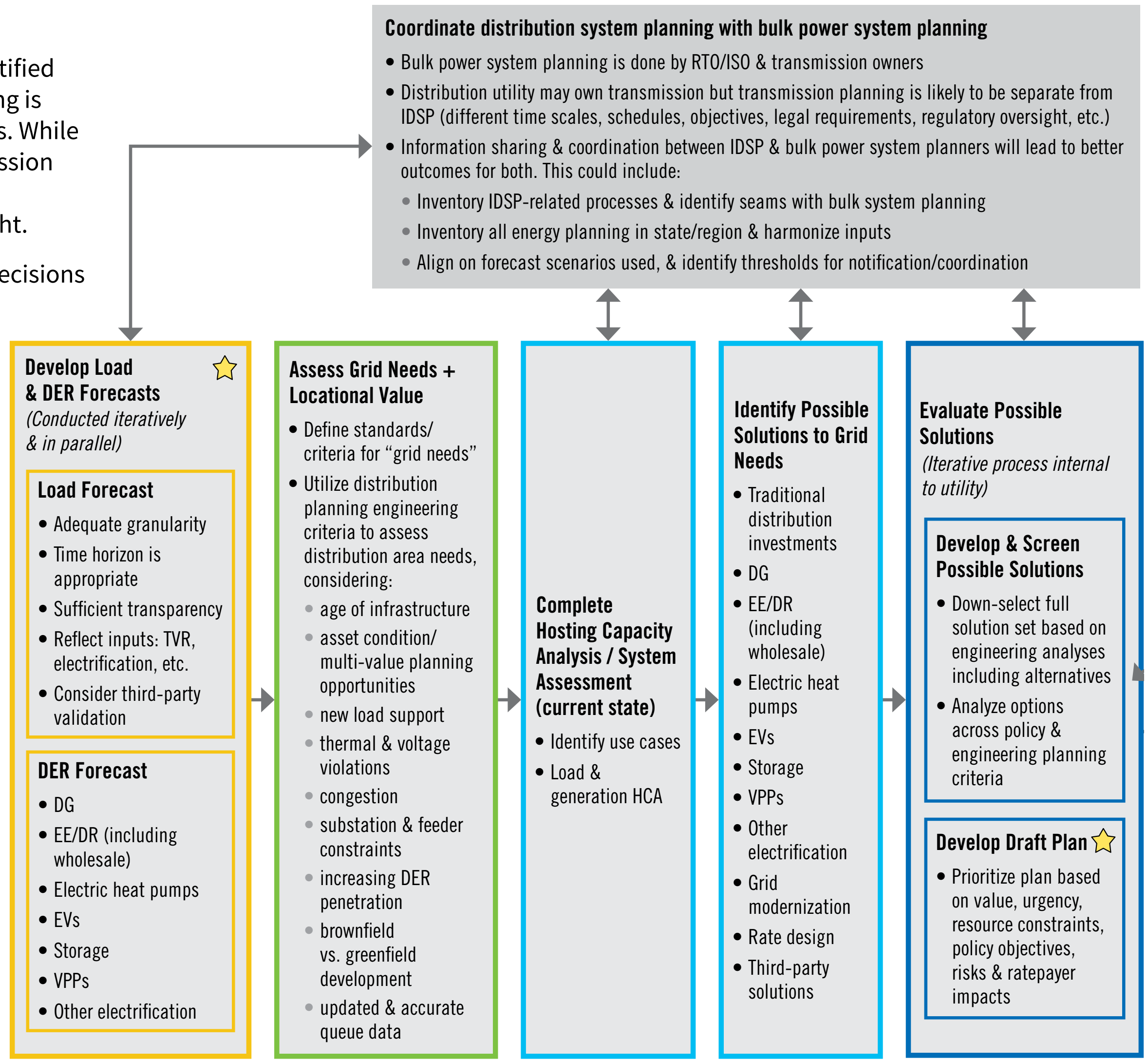
Coordinate Among Distribution System Planners and Bulk System Planners

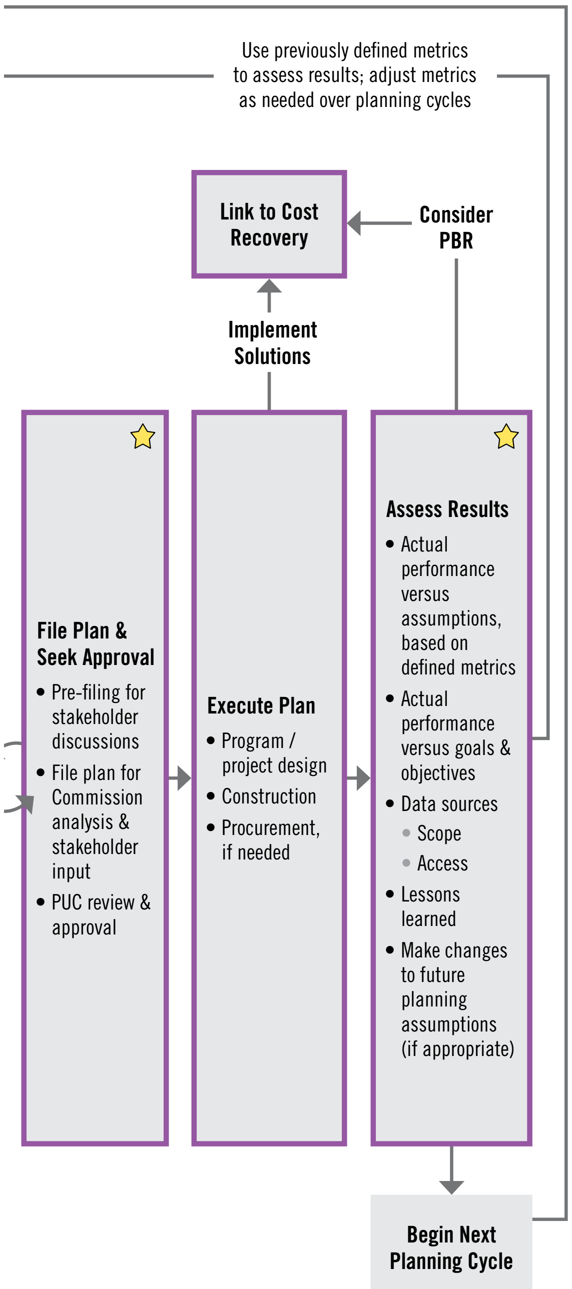
Coordination with the RTO/ISO helps ensure the planning process leads to better outcomes as system needs are identified and as solutions are developed and evaluated. BPS planning is typically conducted by RTOs/ISOs and transmission owners. While distribution utilities may own transmission assets, transmission planning is generally conducted as a separate process with different time scales, requirements, and regulatory oversight.

Coordination can also help ensure that distribution-level decisions appropriately reflect bulk system conditions, including wholesale market dynamics and transmission system capabilities.

In practice, coordination may include aligning forecast scenarios and assumptions, identifying thresholds for notification or coordination (e.g., significant load additions or system impacts), and improving visibility across planning processes to identify areas of overlap or interdependence. While full integration of distribution and transmission planning is not typically practical—particularly in restructured states—ongoing coordination and information sharing can improve planning outcomes across both systems.

> Information sharing between distribution and bulk system planners may include load and DER forecasts, system constraints, and planned investments, enabling alignment across planning processes.





Finalize Plan, Execute, Assess, Begin Next Planning Cycle

File Plan & Seek Approval

Following the development of a draft plan and the evaluation of potential solution portfolios, utilities may conduct **pre-filing engagement with stakeholders**, such as technical discussions or workshops, to present draft findings, refine assumptions, and identify potential areas of concern prior to formal submission. This step also provides transparency into the assumptions, methods, and decisions underlying the proposed investments. Following this engagement, the integrated distribution system plan is finalized and prepared for regulatory review, where applicable.

The plan is then filed with the Commission for review and analysis. The filing typically includes:

- Planning assumptions, scenarios, and data inputs
- Methods and analytical approaches used in forecasting and system assessment
- Identified system needs and their underlying drivers
- The set of evaluated solutions and the rationale for selected investments
- Expected impacts on cost, reliability, and other policy objectives
- Changes from prior planning cycles and explanations for those changes

Regulatory review processes may vary by jurisdiction but generally include opportunities for additional **stakeholder input and Commission evaluation.** This may involve written comments, technical conferences, or other forms of engagement to assess the reasonableness of assumptions, methodologies, and proposed investments.

The integrated distribution system plan serves not only as a planning tool but also as a **documentation mechanism**, providing a transparent record of how decisions were made and enabling regulatory oversight and stakeholder understanding of the planning process.

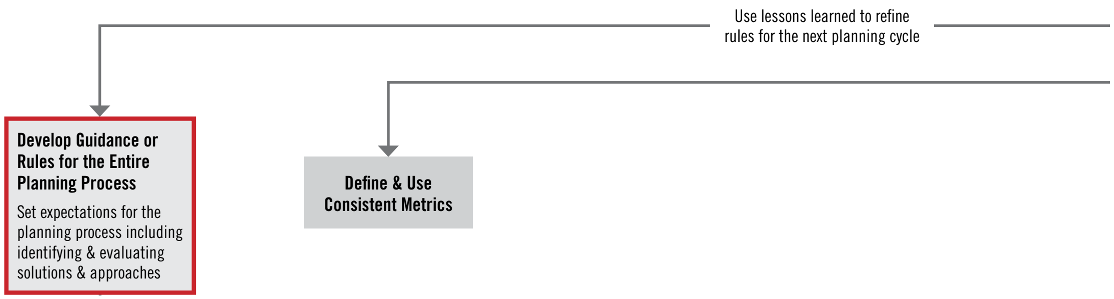
Execute Plan

Once the plan is approved, utilities proceed with implementation through the design and execution of programs and projects. This may include construction, procurement, and operational changes needed to address identified system needs.

Implementation may occur over multiple time horizons depending on the nature and urgency of the investments. Some projects may require additional approvals or coordination prior to execution, particularly where they involve third-party participation or interactions with bulk system infrastructure.

Assess Results

The planning process includes a distinct assessment step in which the results of implemented solutions are evaluated against planning assumptions, defined metrics, and established goals and objectives.



Assessment compares:

- Actual performance versus planning assumptions, based on defined metrics
- Actual performance versus policy goals and objectives
- Outcomes based on available data sources, including considerations of data scope and accessibility

Where applicable, this step may also evaluate the performance and reliability of distributed energy resources, particularly where they are used to defer or replace traditional infrastructure investments.

If there are differences in the certainty or performance of solutions compared to expectations, these insights can be used to refine future planning approaches. Where performance-based regulation (PBR) mechanisms are in place, the use of clearly defined metrics and transparent data sources is particularly important, as performance outcomes may influence utility revenues.

Iterate and Begin Next Planning Cycle

Assessment results and lessons learned are used to inform future planning cycles. By identifying successes, challenges, and areas for improvement, planners can refine assumptions, update methodologies, and adjust investment strategies as appropriate.

In subsequent planning cycles, states and utilities may revisit and update the guidance or rules established at the outset of the process, rather than starting from scratch. Metrics may also be refined over time to better reflect evolving policy priorities and system needs.

Assessment results and lessons learned may also be shared with policymakers to support consideration of updates to relevant policies and regulatory frameworks.

This iterative process is intended to evolve over time, with each planning cycle building on prior results to improve system outcomes and planning effectiveness.

Participants in the NARUC-NASEO Initiative: Comprehensive Electricity Planning in an Era of Load Growth were from the following 24 states and Washington, DC:

- California
- Colorado
- Connecticut
- District of Columbia
- Illinois
- Indiana
- Iowa
- Kentucky
- Louisiana
- Maine
- Maryland
- Massachusetts
- Michigan
- Minnesota
- Missouri
- New Hampshire
- New Mexico
- New York
- North Carolina
- North Dakota
- Pennsylvania
- South Carolina
- Utah
- Virginia
- Washington

Acknowledgments and Disclaimers

This publication and its companion roadmaps were the result of robust engagement with NARUC and NASEO members from 28 state agencies across 24 states and Washington, DC who joined the **NARUC-NASEO Initiative: Comprehensive Electricity Planning in an Era of Load Growth** and attended virtual and in-person workshops. Participants contributed their own perspectives and expertise throughout the development of these materials, not formal positions of their states. States represented include the list at left.

The initiative was led by Danielle Sass Byrnett in the Center for Partnerships & Innovation at NARUC) and Kirsten Verclas at NASEO. Text and graphics were prepared by Celia Tandon, Katerina Stephan, Athindra Venkatraman, and Kaitlyn Bunker of RMI under contract to NARUC.

In addition, a diverse group of experts representing federal agencies, DOE National Laboratories, utilities, research institutions, nonprofit organizations, industry associations, and technology providers provided insights to support development of the flowcharts and roadmaps. Feedback from dozens of reviewers was incorporated to ensure that the flowcharts and roadmaps reflect current and emerging best practices to support state decision-makers. Particular thanks are due to Jeffrey Loiter, NARUC, for his detailed review of an earlier version of the Emerald roadmap.

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About NARUC

NARUC is a non-profit organization founded in 1889 whose members include the governmental agencies that are engaged in the regulation of utilities and carriers in the 50 states, the District of Columbia, Puerto Rico and the Virgin Islands. NARUC's member agencies regulate telecommunications, energy, and water utilities. NARUC represents the interests of state public utility commissions before the three branches of the federal government. The NARUC Center for Partnerships & Innovation (CPI) builds relationships, develops resources, and delivers training to assist state commissions contending with complex current and emerging issues. NARUC CPI conducts work across five key energy areas and many topics within each: generation; transmission; distribution; customers; and critical infrastructure preparedness, response, and resilience.

About NASEO

NASEO is the only national nonprofit organization representing the governor-designated energy directors and their offices – the State Energy Offices – from the 56 States and Territories across the nation. Formed by the states in 1986, NASEO facilitates sharing of best practices among states, serves as a technical and policy resource for states, and advocates the interests of State Energy Offices to Congress and federal agencies.