Integrated Planning Guidebook

A PRACTICAL COORDINATION FRAMEWORK FOR ELECTRICITY PLANNERS

A Report by the
Energy Systems Integration Group's
Integrated Planning Task Force

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ESIG
ENERGY SYSTEMS
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The Energy Systems Integration Group is a nonprofit organization that marshals the expertise of the electricity industry's technical community to support grid transformation and energy systems integration and operation. More information is available at https://www.esig.energy.

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Integrated Planning Guidebook: A Practical Coordination Framework for Electricity Planners

A Report by the Energy Systems Integration Group's Integrated Planning Task Force

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Abbreviations

ACPF	AC power flow
ACOPF	AC optimal power flow
AMI	Advanced metering infrastructure
CEM	Capacity expansion model
DER	Distributed energy resource
DERMS	DER management system
EMT	Electromagnetic transient
FERC	Federal Energy Regulatory Commission
IBR	Inverter-based resource
IRP	Integrated resource planning
LMP	Locational marginal price
PCM	Production cost model
PV	Active power-voltage
QV	Reactive power-voltage
SCADA	Supervisory control and data acquisition
UACPF	Unbalanced AC power flow

Executive Summary

Integrated planning, with its ability to coordinate across multiple planning areas to identify investments most beneficial to the grid overall, is an essential evolution for reliable and affordable electricity systems. Its adoption is driven by the growing need to incorporate short-term operational detail into long-term system planning in an increasingly complex grid. This guidebook presents a practical approach that organizes integrated planning across four primary planning areas—generation, transmission, distribution, and customer loads and resources. The guidebook uses these areas to promote shared understanding among planners, demonstrate the value of integration, and provide a concrete framework and organizational strategies for effective integration.

A wide range of pressing industry challenges are driving this need, including rapidly changing policies and regulations, rising levels of inverter-based resources and their impact on grid stability, significant and uncertain load growth, rapid technological advancements at the grid's edge, complex value-stacking in investment decisions, increasingly severe and frequent weather events that affect both generation and demand, and aging infrastructure. Since these challenges affect each planning area differently, cross-functional planning techniques are needed to ensure cohesive and efficient decision-making. Integrated planning is that technique.

While definitions of integrated planning may vary across institutions and contexts, this guidebook uses the definition of integrated planning adopted by the accompanying ESIG report, *Foundations of Integrated Planning*:

> a comprehensive energy system planning approach that coordinates across systems to develop affordable, reliable, and robust investment plans. Integrated planning coordinates across electricity generation, transmission, distribution, and customer loads and distributed energy resources, and may also consider interactions between the electricity system and other energy systems (ESIG, 2025a).

The guidebook begins by defining the current state of power system planning by delineating each planning area and its respective modeling domains. These areas and domains are evaluated along four dimensions: scope, scale, time horizon, and action. The four dimensions enable readers to discern modeling trends, understand their contextual significance, and appreciate inter-dependencies between different planning areas and modeling domains.

Building on this foundation, the guidebook introduces a comprehensive integrated planning framework that emphasizes information exchange across five planning interfaces: generation/transmission, transmission/distribution, customer/distribution, generation/distribution, and customer/generation. The framework has three progressive stages for each of these planning interfaces (Figure ES-1). By applying this staged approach, organizations can enhance grid reliability, optimize investment decisions, and efficiently incorporate new technologies.

While integrated planning has more complexity than traditional planning approaches, it has tremendous value for harnessing the interconnected nature of modern power systems and maintaining reliable electricity service at least cost. By adopting a comprehensive and iterative framework, integrated planning delivers significant benefits across multiple dimensions (Figure ES-2, p. xii).

The guidebook introduces a comprehensive integrated planning framework that emphasizes information exchange across five planning interfaces: generation/transmission, transmission/distribution, customer/distribution, generation/distribution, and customer/generation.

The guidebook articulates the tangible value that integrated planning brings to the power system, including enhanced reliability, cost efficiencies, and improved decision-making processes. It also offers specific examples to illustrate these benefits in real-world integration applications.

FIGURE ES-1

Framework of Three Progressive Stages for Each of the Five Planning Interfaces

Walk **stage**	***Jog*** **stage**	***Run*** **stage**
Establishing foundational communication, trust, and shared understanding among stakeholders and planning teams	Aligning key inputs, outputs, and planning assumptions across different modeling domains and planning areas to create consistency and interoperability	Executing fully integrated models that enable cross-planning area decision-making and optimization

Source: Energy Systems Integration Group.

FIGURE ES-2

Benefits Delivered by Integrated Planning Across Multiple Dimensions

Lower costs	Integrated planning optimizes resource allocation, eliminating redundancies and reducing overall expenditures.
Increased system resilience	Planning with a comprehensive view of the energy system strengthens the system's ability to withstand disruptions, thus increasing safety, reliability, and adaptability in the face of changing demands.
Streamlined processes	Integrated planning promotes smoother utility operations by enabling coordination and consistent data sharing across planning areas.
Data integrity	Integrated planning standardizes assumptions and shared datasets for planning across generation, transmission, distribution, and customer loads and resources, thus reducing errors and improving process efficiency and electricity system reliability.
Accurate benefit accounting	Integrated planning avoids double-counting benefits while ensuring that the unique advantages of each planning area are effectively incorporated into system-wide strategies. Integration also enables a clearer assessment of reasonable reliance on markets and power purchases, ensuring that system benefits are considered not only internally but also in the context of broader market interactions and regional coordination.
Ability to balance competing objectives	Integrated planning enables trade-off analysis among priorities, such as maintaining grid reliability, ensuring grid resilience, and minimizing costs. By providing a comprehensive view of system needs and objectives, integration also facilitates more meaningful stakeholder engagement.

Source: Energy Systems Integration Group.

Industry spotlights from experienced professionals are interspersed throughout the guidebook to provide additional real-world insights and promising practices.

In addition to providing an iterative framework, the guidebook outlines fundamental concepts for integrated planning software. Rather than advocating for a specific tool, it introduces a set of software principles that make the implementation of integrated planning frameworks accessible to planners of any technical background.

Finally, the guidebook shows how integrated planning is not just a technical exercise—it is an organizational shift. Successful adoption requires strong leadership, cross-functional collaboration, and a commitment to breaking down traditional silos. The leadership perspective offered in this guidebook highlights the key steps necessary to drive these advances, providing a practical roadmap that utilities, policymakers, regulators, and industry stakeholders can use to implement meaningful change in power system planning in step with evolving energy systems.

By embracing integrated planning, the power sector can move toward a more resilient, efficient, and affordable future.

Introduction

The electricity industry is undergoing a rapid transformation. It is more challenging than ever to plan infrastructure upgrades and invest in new assets to keep up with system demands while maintaining reliability and affordability. Simultaneously adopting new technologies, increasing electricity demand across sectors, and addressing aging infrastructure add complexity. The relatively static planning processes and tools were originally developed for a very different power system, with significantly less operational variability, and do not effectively capture the dynamism of power systems today.

There is a critical need for integrated planning processes that bridge the gap between long-term planning and actual operational conditions across multiple planning interfaces involving generation, transmission, distribution, and customer loads and resources. While some integrated planning approaches aim toward redefinition of planning areas, which can make the transition to integrated planning unapproachable, this practical guidebook offers guidance for power system planners by approaching integrated planning as enhanced coordination of *existing* planning areas within electric power system planning.

This practical guidebook offers guidance for power system planners by approaching integrated planning as enhanced coordination of existing planning areas within electric power system planning.

Challenges for Traditionally Siloed Planning Approaches

For decades, electricity flowed in a unidirectional path, from centralized dispatchable generation to higher-voltage transmission networks, then to lower-voltage distribution networks, and ultimately to customers. This flow pattern presented many opportunities to simplify, shape, and, more importantly, separate planning processes at logical interfaces. Planning was segmented for generation planners, transmission and distribution planners, and utility staff who interacted directly with customers. Planning focused on ensuring sufficient generation and infrastructure to meet forecasted peak demand, an approach that was effective when power generation was centralized and demand patterns were predictable. The simplicity of this workflow allowed planners to focus on their portions of the system, and this approach yielded a reliable supply and delivery of electricity.

Several changes now challenge this traditional planning approach. First, large-scale variable energy resources undermine the core assumption of dispatchable generation. Planning today also confronts accelerated load growth from electrification, data centers, and new industrial demands, straining both generation and grid infrastructure. Together, these trends drive the need for coordinating resource planning with transmission planning. The degree of uncertainty and the dimensionality of the planning problem have exploded, with queued proposals for new generation, loads, and infrastructure often exceeding the rating of existing power systems—all while aging transmission systems demand replacement and upgrades.

The rapid pace of technological innovation also requires faster and more flexible investment strategies that can be unlocked with integrated planning. Lastly, the rise of distributed energy resources (DERs), such as solar photovoltaic systems, battery storage, and electric vehicle charging systems, has made power flow bidirectional. Power now flows from the grid to customers and from

customers back to the grid. This challenges the fundamental unidirectional principle of traditional planning processes, and the logical next step in planning is creating planning processes for bidirectional power flows.

Exploring Best Practices Through This Guidebook

Today, the primary solution to address these challenges comprehensively is to integrate planning processes that are currently largely siloed in the electric power industry. To facilitate better understanding and explore potential best practices for integrated planning, the Energy Systems Integration Group (ESIG) convened a task force including planning experts from utilities, regional transmission operators/independent system operators, U.S. Department of Energy national laboratories, other research organizations, software vendors, consultants, and other practitioners. Three reports were produced which contribute to the nascent knowledge base of integrated planning practices.[1] The first report, *Foundations of Integrated Planning*, defines integrated planning and why it is needed, followed by a broadly applicable framework for comprehensive planning. This is the second report, which provides practical recommendations for today's electricity system planners to advance toward increasing levels of integration through a walk/jog/run approach. The third report, *Optimization for Integrated Electricity System Planning*, focuses on the opportunities and current challenges in using economic optimization–based capacity expansion modeling to consider a broader set of integrated planning constraints and investment opportunities.

This guidebook is structured as follows. The next chapter provides an overview of the new challenges that planners are experiencing across planning areas and defines necessary integrated planning solutions that span multiple planning areas. Following that is a structured overview of planning for generation, transmission, distribution, and customer loads and resources, as well as the modeling domains used. The next chapter introduces a framework for integrated electricity system planning. The framework outlines key integration opportunities across several planning interfaces, including generation/transmission, transmission/distribution, customer/distribution, generation/distribution, and customer/generation. The guidebook then highlights the value of these integrations and outlines key concepts for implementing integrated planning workflows in software. It concludes with targeted recommendations for electricity industry leadership seeking to implement integrated planning. Spotlights from interviews with industry experts are given throughout the guidebook.

1 All three reports can be found at https://www.esig.energy/integrated-planning/.

New Challenges with Current Processes

As power systems undergo rapid transformation, traditional planning approaches are being challenged by rapid load growth, integration of variable inverter-based resources (IBRs) and a resultant decrease in synchronous generation, adoption of DERs, and the growing coupling between the power system and other industry sectors and infrastructures. This chapter outlines some of the ongoing changes that drive the need for deeper integration of planning across electric generation, transmission, distribution, and customer loads and resources.

Rapidly Changing Policies and Regulations

In the past, energy policies and regulations evolved gradually. Today, they are shifting quickly due to rapidly growing electricity loads, shifting economic incentives, changing market rules, and other factors. While the adoption of wind and solar was initially driven by policies and consumer demand, it is now primarily driven by economics, as these resources have become the cheapest generation resources. At the same time, they require significant transmission infrastructure, making coordinated generation and transmission planning essential. Energy system planners navigate complex and often uncertain regulatory landscapes across local, state, and federal levels. Misalignment between policy changes and infrastructure development can create stranded assets, regulatory bottlenecks, and suboptimal investment decisions. Examples of regulations that are intended to address these challenges include the Federal Energy Regulatory Commission (FERC) Order 1920, which motivates coordination between generation and transmission planning; FERC Order 2222, which aims to enable DER participation in electricity markets; and FERC Order 2023, which reforms the interconnection process to streamline the integration of new generation resources and incentivizes coordinated planning by generation and distribution planners and with customer resources (FERC, 2021, 2023, 2024).

Managing Inverter-Based Resources and Grid Stability

The increasing adoption of IBRs, including solar, wind, and battery storage technologies, is fundamentally changing grid dynamics (Kroposki et al., 2017; Denholm et al., 2020; ESIG, 2021). Unlike traditional synchronous generators, IBRs operate with power electronics that can impact grid stability in new and unexpected ways, particularly in weak-grid conditions. The power system has historically been designed and built on the assumption that synchronous machines would be the dominant devices on the system and therefore impart a particular set of operating conditions around which stability mechanisms have been constructed and tuned. As

New planning challenges such as system strength assessments for IBR-rich system regions and adverse control interactions between IBRs require advanced modeling across historically siloed teams.

IBRs become more commonplace, the industry must align with a change in these foundational principles for power system planning and design. New planning challenges such as system strength assessments for IBR-rich system regions and adverse control interactions between IBRs require advanced modeling (Hatziargyriou et al., 2021; Kenyon et al., 2023) across historically siloed teams.

Planning for Significant and Uncertain Load Growth

Unlike the relatively stable and predictable load growth of the past, today's electricity demand is growing at an unprecedented pace due to electrification, data center expansion, and new industrial loads (EPRI, 2024a). The timing, location, and magnitude of this demand are highly uncertain, making traditional planning approaches insufficient (Xcel Energy, 2021; Biewald et al., 2024).

Rapid Technological Improvement at the Grid Edge

The rapid deployment of new technologies, including battery storage, virtual power plants (Downing et al., 2023; Long, Long, and Frick, 2025), advanced electrified heating, and flexible electric vehicle charging, is reshaping investment and planning decisions (U.S. DOE, 2020).[2] In addition, advances in bulk-grid technologies—such as advanced conductors, high-strength low-sag transmission lines, and multi-terminal high-voltage DC systems—are also enabling grid modernization. Unlike conventional grid infrastructure, these distributed and flexible resources

Unlike conventional grid infrastructure, distributed and flexible resources require coordination across multiple stakeholders, from transmission operators to utilities and customers, and across different regulatory and operational areas.

2 A virtual power plant is a network of decentralized energy resources aggregated and managed through software to function like a single power plant.

require coordination across multiple stakeholders, from transmission operators to utilities and customers, and across different regulatory and operational areas.

Complexity of Value Stacking in Investment Decisions

Traditional grid investments were based on single-purpose assets (e.g., a power plant for generation, a transmission line for delivery). However, modern resources such as behind-the-meter battery storage provide multiple grid services, including capacity, voltage management, resilience, and power quality (Martini, Succar, and Cook, 2024; Table 1). Capturing these benefits requires coordinated investment planning that considers retail rate structures, distribution system upgrades, and bulk power system needs. Without the integration of planning processes, the full value of these resources may be left untapped or misaligned with broader system goals.

Increasing Weather Events and Risks to Infrastructure Resilience

Climate change is increasing the frequency and severity of natural disasters, posing new risks to energy infrastructure. Rising temperatures can increase peak electricity demand while simultaneously reducing generation and transmission capacity. More frequent and intense wildfires threaten power lines, high winds can lead to tower failures, and floods and droughts impact hydroelectric generation and grid reliability. Similarly, wind and solar output fluctuate during extreme weather events. As these risks grow, energy planners must incorporate resilience to extreme weather events into investment decisions—enhancing infrastructure standards, diversifying transmission routes, and incorporating advanced forecasting and risk assessment models. If not carefully accounted for, reliance on historical generation profiles can misrepresent future resource availability, potentially leading to planning decisions that underestimate the need for additional transmission and generation capacity (EPRI, 2024b).

Aging Infrastructure

Many transmission and distribution networks and generation resources are reaching the end of their operational lives, presenting both a challenge and an opportunity. Rather than simply replacing aging assets, there is an opportunity to modernize infrastructure to better align with future system needs. An optimal approach would ensure that upgrades are strategically coordinated across the grid to optimize performance and resilience (De Luca et al., 2024). Additionally, aging generators are being retired due to inefficiency, economic constraints, or policy shifts. These retiring generators are often replaced by a larger number of smaller, distributed energy resources, which may not be located in the same areas as the original generating facilities. This shift alters power flows across the system, requiring careful planning to maintain reliability.

Rather than simply replacing aging assets, there is an opportunity to modernize infrastructure to better align with future system needs. An optimal approach would ensure that upgrades are strategically coordinated across the grid to optimize performance and resilience.

Defining Integrated Planning

The challenges discussed above affect various aspects of power system planning in different ways. To effectively address these challenges we need planning paradigms that span multiple areas. Integrated planning offers a framework for connecting traditionally separate planning areas based on the specific challenges an organization aims to solve. While definitions may vary across institutions and contexts, this guidebook uses the definition of integrated planning adopted by the ESIG report, *Foundations of Integrated Planning:*

> Integrated planning is a comprehensive energy system planning approach that coordinates across systems to develop affordable, reliable, and robust investment plans. Integrated planning coordinates across electricity generation, transmission, distribution, and customer loads and DERs, and may also consider interactions between the electricity system and other energy systems (ESIG, 2025a).

This approach is rooted in collaborative analysis and adaptive strategies, enabling stakeholders to address the intersecting challenges of cost, resilience, sustainability, and customer engagement. Integrated planning builds on decades of thought leadership (IAEA, 1984; EPRI, 2018, 2022; HECO, 2023; Keen et al., 2023; SRP, 2023) and is not just a tool, but a philosophy for advancing power systems.

INDUSTRY SPOTLIGHT

A Vertically Integrated Utility Perspective on the Need for an Integrated Planning Framework

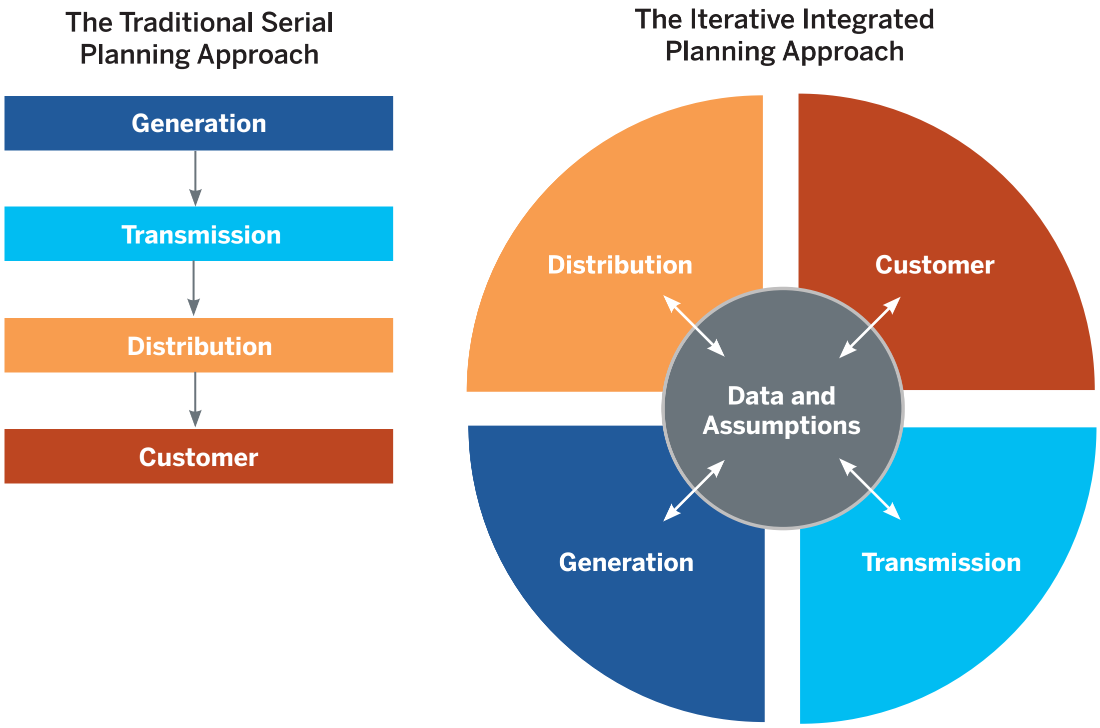
"These challenges highlight a need for a new planning approach—one that focuses not just on transmission and distribution upgrades necessary for reliable interconnection of renewable generation, not just on transmission upgrades to move renewable generation from one part of the system to another part of the system, not just on designing transmission and distribution grid to be more resilient, not just on ensuring that grid operators have at their disposal the tools and technologies to seamlessly manage demand and supply on both transmission and distribution systems—but one that focuses on the totality of it—an integrated planning framework."

IEEE Power and Energy Society Industry Technical Support Leadership Committee, 2023, p. 22.

Figure 1 (p. 7) illustrates the transition from traditional, serial power system planning to a more comprehensive, integrated approach required for modern grids. This framework fosters continual data exchange among planners for generation, transmission, distribution, and customer loads and DERs. By enhancing information flow and feedback across planning areas, integrated planning better represents and anticipates the operation of diverse power systems with evolving loads and generation sources.

FIGURE 1

Comparison of Traditional and Integrated Planning



Source: Energy Systems Integration Group.

INDUSTRY SPOTLIGHT

Comments from an Integrated Planning Expert

"I believe it is essential to remember that the electrical system is a complex technical system, probably one of the most complex systems designed by humans. Various locally optimal solutions, arranged in a patchwork, will not necessarily ensure a globally optimal system, both today and in its future evolution. Integrated planning allows us to envision an "optimal" electrical system and to guide its future development. It does so despite the current rules, practices, and habits that have been developed for the system we have today, but which is evolving at a rapid pace."

Overview of Electric Power System Planning: Structured Across Consistent Dimensions

Integrated planning thrives when planners see the bigger picture—how their specific planning areas and modeling domains connect within the broader planning processes for electric power systems. To foster this awareness, this chapter establishes a clear framework for defining planning areas and modeling domains across consistent dimensions. By doing so, planners can better navigate planning trends, understand the roles of their counterparts, and collaborate more effectively in shaping a cohesive integrated planning process.

This chapter establishes a clear framework for defining planning areas and modeling domains across consistent dimensions, to help planners better navigate planning trends, understand the roles of their counterparts, and collaborate more effectively in shaping a cohesive integrated planning process.

Traditional Objectives of Electric Power System Planning

The traditional objectives of power system planning encompass several key aspects that ensure the reliable and affordable delivery of electricity. **Resource adequacy** ensures that sufficient generation capacity is available to meet future demand (IAEA, 1984; Bergman et al., 2016). *Reliability* ensures a consistent and uninterrupted power supply to consumers, addressing potential disruptions or failures in the system (IAEA, 1984; Bergman et al., 2016; Keen et al., 2023; AEMO, 2024). *Safety* is paramount, with the system designed to protect both infrastructure and personnel from potential hazards (IAEA, 1984; Keen et al., 2023). Finally, *affordability* has traditionally been guided by regulatory agreements emphasizing least-cost planning—ensuring reliable power at the lowest and fair cost (Bonbright, 1961; EPRI, 2022). As new challenges introduce additional requirements for the power system, these objectives continue to evolve, incorporating concepts such as least-regrets decision-making (scenario planning to consider risks, including that costs may be different than expected) and others.

Dimensions of Electric Power System Planning

When planning a power system, it is essential to consider various dimensions that help shape the structure and effectiveness of the plan. The International Atomic Energy Agency (1984) provided a time-tested framework for outlining the dimensions of planning, which we extend for this guidebook. The dimensions of scope, scale, horizon, and action will be referenced throughout the guidebook (Table 1, p. 9).

The Traditional Planning Areas

The electric power system is typically divided into four main planning areas: generation, transmission, distribution, and customer loads and resources. In practice, these areas may be handled by multiple teams within an organization or, in some regions, by teams across different organizations. Here, we define each of these planning areas, exploring their main responsibilities and the modeling domains each typically uses. While the organization of these planning areas varies significantly, one common factor remains: in most organizations, these teams continue to operate in relative isolation from one another. Bringing them into closer proximity through integrated planning will lead to more comprehensive planning processes.

TABLE 1

Definitions and Examples of the Dimensions of Electric Power System Planning

Scope	Scope determines the plan's focus. It outlines the boundaries and objectives of the planning process, specifying what is included and what is excluded. **Example:** The scope of a resource plan might focus on generation capacity expansion, complying with state regulations, and minimize the risk of uncertain load growth, while not considering other areas of power system planning like distribution feeder upgrades.
Scale	Scale determines the size of the planned implementation. It also reflects whether the plan targets a specific area or takes a broader, more comprehensive approach. **Example:** The scale of a plan could involve a localized effort, such as hosting capacity for rooftop solar in a utility's service area, or an interconnection-level effort to provide sufficient generation and transmission capacity for large new loads like data centers.
Horizon	Horizon defines the duration over which the plan is intended to be implemented. **Example:** A short-term plan might focus on upgrading distribution poles to withstand higher wind levels during storms in the next three to five years, while a long-term plan could aim for undergrounding distribution infrastructure for certain critical facilities.
Action	Action defines the decisions informed by the plan. **Example:** An integrated resource plan is intended to inform generation investment or retirement decisions but is not intended to prioritize upgrade decisions for distribution systems.

Source: Energy Systems Integration Group.

Overview of Generation Planning

General Responsibilities and Decisions

Generation—the production of electrical power by coal, natural gas, nuclear, or renewable sources like geothermal, hydro, biomass, wind, and solar—is an essential element of integrated planning to meet future energy demand reliably, at least cost, using a mix of resources. Table 2 lays out scope, scale, horizon, and action related to generation planning.

TABLE 2

Generation Planning: Scope, Scale, Horizon, and Action

Scope	Generation planning encompasses the strategic planning and development of generation and storage (primarily utility-scale) assets to ensure an adequate, reliable, and least-cost electricity supply that is responsive to changes in the planning environment.* These changes include assessing various resources, while considering operational constraints and other factors, such as costs, fuel availability, emerging technologies, and regulatory compliance. For many utilities, generation planning is the foundation of the integrated resource planning process (see "Integrated Resource Planning" for more information). Generation planning also can inform near-term operations.
Scale	The scale of generation planning can range from localized efforts to state, regional, or national strategies. For example, a rural electric cooperative utility may develop a plan to integrate more solar and wind generation, while a state-level plan to do so may require coordination among multiple utilities and regulatory bodies.
Horizon	Generation planning operates over multiple time horizons, including short-term operational plans (1 to 5 years), resource investment plans (5 to 25 years), and long-term strategic plans (15 years or more). A short-term plan might focus on optimizing existing resources and improving efficiency over the next 3 to 5 years, while long-term plans may extend 20 to 30 years into the future, aiming for major shifts in the generation mix.
Action	Generation planning informs investment decisions on building or procuring new utility-scale generation and storage assets and retiring aging or non-economic facilities, as well as informing sustaining capital investments at existing generation facilities by evaluating their anticipated level of utilization and estimated economic life.

* Some methods incorporate aggregate contributions by DERs, while the detailed planning for these assets is covered in the "Planning for Customer Loads and Resources" section.

Source: Energy Systems Integration Group.

Modeling Domains

Optimization typically serves as a foundational framework in generation planning, enabling planners to systematically evaluate decisions under complex and interdependent constraints. Primary modeling domains include capacity expansion modeling (CEM), probabilistic resource adequacy assessment, and production cost modeling (PCM). Complementing and supporting these three primary modeling domains are other heuristic tools for assessing resource adequacy, forecasting demand growth, and performing other key functions.

This guidebook presents recommendations on integrated planning processes between generation planners and other planning areas (transmission, distribution, and customer loads and resources). While we discuss the value of enhancing the representation of these areas in generation planning models, the focus in this report is the iterative process between the models used by different planning teams focused on their respective planning areas. For example, we discuss the value of iterating between PCMs and power flow simulations as a key step to integrated generation planning with both transmission and distribution planning (see "Integration of Generation andd Transmission Planning").

Capacity Expansion Modeling[3]

- **Scope:** Capacity expansion models are primarily used by generation planners at electric utilities and regional power system operators to optimize or predict future investments in utility-scale generation and storage assets. Fundamentally, CEM is an optimization model that minimizes total system costs, including capital expenses, fixed operational expenses, and variable operational expenses. Ideally, CEMs include representations of varying details of transmission and aggregated DERs, including demand response, in terms of existing and potential future capacities that would affect investment strategies in utility-scale generation and storage assets.
- **Scale:** The model commonly applies to large-scale electric utility systems, including utility-scale generation, storage assets, and sometimes transmission and DERs. It also can be used for assessing reliability at regional or national levels.
- **Horizon:** Planners typically run these models to optimize generation planning over 15 to 30 years. CEMs can represent every year in the investment horizon, or, in some cases, the investment horizon is represented, say, every 5 years in a 25-year horizon. For computational tractability, the annual operation of the power system is generally represented for: (1) a selected number of periods, which can be independent time slices that represent different loading and seasonal conditions (e.g., three or five snapshots per month), or (2) continuous hourly chronological periods that represent diurnal variability during different times of the year (e.g., three days per month or two weeks per quarter). Algorithms can be used for selecting representative periods. Hourly representation is particularly valuable for systems that have high levels of variable renewable energy resources, storage resources, or both. For systems with long-duration storage, such as hydro reservoirs, it is important to capture seasonal or year-to-year variations.
- **Action:** The model informs investment or retirement decisions for generation, storage, and potentially transmission and DERs. It also supports policy and regulatory compliance and strategies to minimize system costs. Modeling results are often iterated with separate resource adequacy analysis and passed to a PCM for further evaluation and refinement of targeted investment strategies and scenarios.
- **Key inputs:**
  - Demand forecasts (ideally bottom-up, considering different sectors)
  - Existing generation and storage assets
  - Generation and storage availability time series (e.g., all types of fuels, different types and durations of battery technologies)
  - Transmission system constraints
  - Investment candidates and lead times (new assets and retrofits)

3 The ESIG task force that led the development of this guidebook also produced a report titled *Optimization for Integrated Electricity System Planning: Opportunities for Integrated Planning in Capacity Expansion Models*, which focuses on the opportunities and challenges of using economic optimization capacity expansion modeling to consider a broader set of integrated planning constraints and investment opportunities (ESIG, 2025b).

- Investment costs (e.g., capital, fixed operations and maintenance, variable operations and maintenance)
  - Fuel costs
  - Emissions data
  - Policy and regulatory requirements
  - Market interactions
  - Retirement plans
- **Key outputs:**
  - Optimal investment strategies for new generation, storage, and transmission[4]
  - Retirement and expansion plans for existing assets
  - Projected system operation (i.e., hourly line loading, generator dispatch, etc.), costs, and emissions

Probabilistic Resource Adequacy Assessment

- **Scope:** Probabilistic resource adequacy assessment focuses on evaluating the likelihood that a power system has sufficient generation, transmission, and demand flexibility to maintain a balance between supply and demand under a wide range of scenarios. Mathematically, a probabilistic resource adequacy assessment is typically a Monte Carlo–based probabilistic analysis used to generate and evaluate many possible future grid conditions. These models quantify the likelihood that a power system has sufficient generation, transmission, and flexibility available to balance electricity supply and demand under a wide range of outage, weather, and other operational conditions. These models are generally applied to the results of a CEM (often supported by a PCM).
- **Scale:** The model typically applies to large-scale power systems, including generation, storage, and transmission infrastructure. It assesses system-wide reliability and can be used at utility, subregional, interconnection-wide, or national level.
- **Horizon:** Resource adequacy assessments enable planners to rapidly simulate thousands of years of potential operations under a broad range of probabilistically weighted conditions. These forward-looking screening studies model the seasons, years, and decades ahead to identify potential supply risks and characterize any resource gaps that may need to be filled.
- **Action:** The model informs power system planners and reliability organizations about potential resource inadequacies and supply risks. It helps guide decisions on capacity investments, flexibility strategies, and transmission improvements.
- **Key inputs:**
  - Generation and storage portfolio (unit sizes, reliability statistics, availability time series or outage rates, locations)
  - Variable generation resource hourly profiles, often for many years
  - Transmission infrastructure (transfer capabilities, reliability statistics)
  - Demand profiles, including flexibility characteristics
  - Weather data and stochastic unit failure scenarios
- **Key outputs:**
  - Statistical descriptions of electricity shortfall risk
  - Loss-of-load expectation
  - Loss-of-load hours
  - Expected unserved energy
  - Transmission interface utilization
  - Storage device states of charge
  - Risk assessments disaggregated across time and space

Some resource adequacy models share many characteristics with PCMs, with both simulating chronological grid operations across multiple years (see Box 1, p. 12).

4 Although optimizing transmission investments in a CEM is currently uncommon in industry practice, it is possible.

BOX 1

Comparing Production Cost Models and Other Resource Adequacy Models

PCMs can be used to perform resource adequacy assessments. However, PCMs tend to focus on detailed (and thus slower) optimization-based simulations of a smaller number of scenarios, whereas dedicated resource adequacy tools use reduced-form models and fast decision heuristics to assess physical feasibility (rather than determine economic optimality). Dedicated resource adequacy tools provide a coarser risk screening across a much broader set of possible scenarios, considering the potential impacts of many years of datasets for future weather scenarios and stochastic unit failures without sacrificing computational tractability. These large ensembles of runs (typically involving 100 to 100,000 sets of scenarios) are then consolidated to produce top-level probabilistic risk metrics such as loss-of-load expectation and expected unserved energy.

Production Cost Modeling

- **Scope:** PCMs, also known as production simulations or unit commitment and economic dispatch models, are primarily used by generation/resource planners at electric utilities, regional system operators, and electricity market operators to inform operational and strategic planning decisions, evaluate the operational performance of the system, and ensure that the present and future systems can meet demand and ancillary service requirements at any time during the year. Fundamentally, PCM is an optimization that minimizes variable operational expenses or production costs, which include variable operation and maintenance costs, fuel costs, emissions costs, emissions abatement costs, and start-up/shut-down costs of generators. A PCM can be applied to a network by using the DC power flow approximation approach, known as a nodal PCM. Security-constrained PCM tools can consider the effects of contingencies on electricity system operation.
- **Scale:** PCM applies to power systems at various levels, including utility-scale, regional, and market-wide operations.
- **Horizon:** PCM typically operates at an hourly or sub-hourly resolution (e.g., 5-, 15-, or 30-minute intervals) over time frames that may span days, weeks, or years, depending on the analysis.
- **Action:** The model informs operational and strategic planning decisions, evaluates system performance, optimizes generator dispatch and unit commitment, and identifies transmission and operational constraints. It also supports electricity market operations by simulating energy and ancillary service markets.
- **Key inputs:**
  - Generator costs, electrical specifications, and operational constraints
  - Fuel prices and availability
  - Demand forecasts
  - Generation and storage availability time series (e.g., conventional, wind/solar, battery)
  - Transmission constraints
  - Market participant bids (if modeling a market)
  - Quantity of ancillary services required, including the qualification of generation and storage resources to provide the different types
- **Key outputs:**
  - Optimized generator commitment and dispatch schedules
  - Total system production costs
  - Estimated electricity prices (e.g., locational marginal prices (LMPs))
  - System operational performance metrics
  - Identification of binding constraints (e.g., shadow prices for transmission and operational constraints)

When PCMs represent an electricity market, the minimization of total production (or operational) costs considers the bids of generators, storage assets, and loads that may contribute to the energy market by offering to generate or consume at different prices. These participants may also participate in ancillary service markets such as spinning or frequency reserve requirements, depending on the market.

Together, these modeling domains allow generation planners to explore both traditional scenarios (e.g., baseline demand growth, fuel price fluctuations, policy shifts) and emerging trends (e.g., increased integration of variable energy resources, electrification). By using CEM and PCM in tandem, generation planners can better align investment strategies with future operations, creating a comprehensive and resilient approach to generation planning.

Integrated Resource Planning

Integrated resource planning (IRP) is the process that many utilities use to identify a least-cost, long-term portfolio of generation resources (generation and storage investments, retrofits, and retirements) and demand-side resources (demand response and energy efficiency). The term "integrated" in IRP takes a different meaning than the integration of planning processes discussed in this guidebook. Traditional utility resource or generation planning evolved to IRP in the 1980s as a method to meet electricity demand in the most cost-effective way by evaluating a broader range of resources. IRP continues to evolve with increasingly sophisticated resource planning models (CEM, PCM, and probabilistic resource adequacy assessment), enhanced load forecasting inputs, and more powerful computing resources to allow for detailed chronological representations of time. All of these developments support improved evaluation of emerging technologies.

Today, IRP models can represent the transmission network (either zonal or nodal) to capture transmission constraints that impact the optimal expansion and operation of utility-scale generation and storage assets. When CEM includes transmission investment candidates, modeling captures trade-offs with utility-scale generation and storage. IRP models can also capture the trade-offs between these resources and DERs, including aggregations of distributed solar, behind-the-meter batteries, demand flexibility, and energy efficiency by including representations of distribution network–connected assets and customers. An emerging area to support this type of analysis is incorporating distribution system investment candidates in CEM—both DERs and traditional distribution network capacity upgrades—which captures the cost of upgrading infrastructure to increase DER hosting capacity. A major challenge in integrating transmission, distribution, and DER investment candidates in CEMs is computational tractability (EPRI, 2023). Another challenge is that transmission and distribution infrastructure investments are often driven by reliability needs that are not practically captured by IRP models that are based on energy and active power needs (with no consideration of reactive power and voltage).

There have been major developments in IRP processes to improve the way they capture the trade-offs between utility-scale generation and storage assets and the rest of the system, including transmission and distribution networks and DERs, such as customer flexibility. Biewald et al. (2024) offer best practices and practical guidance to develop technically sophisticated, state-of-the-art electric utility resource plans.

Overview of Transmission Planning

General Responsibilities and Decisions

Transmission networks consist of high-voltage power lines, up to 500 kV in most areas, with some instances of 765 kV. Sub-transmission voltage level definitions vary by organization and system topology. They can be as high as 96 kV and range down to typical distribution feeder voltages of less than 35 kV. Rather than a specific voltage threshold, the distinction is based on the function the lines serve. These meshed transmission and sub-transmission networks work together to efficiently transport electricity, ensuring reliability through redundancies and minimizing losses before reaching load centers.

Table 3 (p. 14) presents the scope, scale, horizon, and action related to transmission planning.

TABLE 3

Transmission Planning: Scope, Scale, Horizon, and Action

Scope	Transmission planning focuses on the reliability and stability of the high-voltage bulk power system, ensuring that it has sufficient capacity to deliver energy from the source of generation to the point of consumption. This includes evaluating current infrastructure, identifying necessary upgrades, and planning for future expansions to accommodate growing demand and new generation sources. Planners assess reliability by subjecting various types of models of the transmission system under study to sets of contingencies representing possible physical disturbances to ensure compliance with industry regulations. Historically, a system would be planned based on peak load and an N-2 contingency. Transmission planning also plays a role in evaluating interconnection requests for new bulk power system assets, particularly as these relate to the reliability and stability of the power system.
Scale	The scale of transmission planning can vary from utility service area, to in-state, to interconnection-wide. Utility planning addresses localized transmission constraints and ensures that power flows efficiently within its service area. Larger-scale planning may involve coordinating across multiple states or balancing authority areas to ensure efficient electricity transfer between regions and allow regions experiencing different weather patterns to support one another. Sub-transmission planning may be handled by transmission planners or distribution planners, depending on the utility.
Horizon	Transmission planning operates on both short-term and long-term time horizons. Short-term plans, spanning 1 to 5 years, focus on immediate, short-run system reinforcements and operational adjustments to maintain reliability under rapidly changing conditions. Depending on the speed of installation, this may include processing interconnection requests for near-term generation and large loads. But since most transmission capacity additions require more than 5 years to plan and build, the short-term activities of transmission planners are often focused on operational-type support such as post contingency switching. Long-term plans, often looking 5 to 20 years ahead, anticipate future grid needs based on demand forecasts, emerging energy technologies, and regulatory changes. Most often, these plans are aimed at specific system investments that are intended to be made in the 5- to 10-year time frame.
Action	Transmission planning informs key decisions related to expansion of high-voltage grids, reliability improvements, and regulatory compliance. Planners provide insights that guide investment in new transmission lines, substation and line upgrades, and system reinforcements to reduce congestion and ensure resilience against disruptions. Their work informs regulatory filings, infrastructure funding decisions, and operational strategies.

Source: Energy Systems Integration Group.

Modeling Domains

Transmission planners have a wide variety of modeling domains and analysis approaches, but the majority are built upon the balanced AC power flow (ACPF) model. Planners use either steady-state or dynamic analysis, based on the type of situation or phenomena being analyzed. The two common dynamic modeling approaches in transmission system planning are phasor-domain/transient simulation and electromagnetic transient (EMT) simulation. Within these classes, there is a range of analytical approaches, such as contingency analysis, voltage stability assessments, short-circuit/fault modeling, small-signal stability, and transient (large-signal) stability. We discuss each of these tools in detail, followed by short descriptions of frameworks that use these tools for transmission planning purposes.

Balanced AC Power Flow

- **Scope:** ACPF (also known as load flow)—the simulation of the physics of power within an AC electrical network—involves determining the voltages, currents, and real and reactive power transferred throughout the system under steady-state conditions. Mathematically, ACPF analysis involves solving nonlinear equations derived from Kirchhoff's laws of voltage and current. It is crucial in the engineering assessment of operation and planning of power systems to ensure that the network operates within its physical and operational limits.
- **Scale:** The model applies to power systems at various levels, from utility and regional transmission networks up to interconnection-wide.
- **Horizon:** The model determines steady-state operating conditions, including line loading and system voltages, at representative snapshots of system operation where all generator active power outputs and demand consumptions are held static. As a result, the model can be used sequentially over different time frames for planning and operational assessments in the near and long term.

- **Action:** The model informs power system planning, operational decision-making, real-time system monitoring, contingency analysis, energy market operations, the integration of generating resources, and compliance with industry standards.
- **Key inputs:**
  - System topology (network configuration), including precise demand and generation position
  - Line parameters (impedance, admittance)
  - Generator and other grid device characteristics (capabilities, voltage setpoints)
  - Load demands
  - System constraints
- **Key outputs:**
  - Bus voltages (magnitude and angle)
  - Generation limits, particularly reactive power constraints
  - Active and reactive power flows on each line, and associated loading
  - System losses

INDUSTRY SPOTLIGHT

Color-Commentary on "Steady-State" by Nicholas Miller (HickoryLedge LLC)

"Of course, the system is never truly in steady-state. Conditions change constantly with a range of speed. Power flow analysis captures a snapshot of operation during which a specific profile of generation commitment and dispatch is matched with a specific customer load and loss profile. The rapidly moving dynamics, such as those governing the electromagnetics and controls of machines, transmission control devices, and some ancillary services, are assumed to have achieved their objectives or hit limits. The slowly moving dynamics, such as daily variation in load, changes in unit commitment, and most market functions, are frozen at the selected operating point."

Short-Circuit/Fault Modeling

- **Scope:** Short-circuit analysis evaluates fault current levels in electrical systems to meet equipment short-circuit current ratings (especially circuit breakers), protection system coordination, proper relay settings, and fault isolation. While typically a system operator study engineers' task, it is included here due to its recent application to stability assessments for planning. Mathematically, short-circuit analysis applies network theory and linear algebra to solve fault currents using methods such as symmetrical components and impedance matrix calculations. It is essential for assessing system resilience, identifying potential equipment damage risks, and ensuring compliance with safety standards. A new application of short-circuit modeling identifies regions of the system with relatively lower short-circuit ratios, which can indicate weak system strength and potential instability for IBRs.
- **Scale:** Short-circuit/fault modeling can be applied at both transmission and distribution, depending on the type of fault being investigated and the region of interest, with no substantial computational limitations. However, the ability to accurately characterize the fault response of IBRs (which do not present simple physics-derived fault responses as synchronous machines do) with steady-state calculations is under investigation.
- **Horizon:** This modeling is typically conducted as a steady-state or event-based analysis to evaluate system conditions under fault scenarios. It is repeated periodically to reflect system upgrades or changes in protection schemes.
- **Action:** Short-circuit/fault modeling identifies potential equipment overstress conditions due to high fault currents. As a seed to dynamic simulations, these establish a contingency for further time-domain assessments. Additionally, low short-circuit responses of a system in particular regions have been correlated with poor IBR performance.
- **Key inputs:**
  - System topology, including network structure and protective device locations

- Impedance data and phase configurations for lines, transformers, and other equipment
- Generator, storage, and DER fault characteristics, including short-circuit current ratings
- Protection device settings (relay pickup values, breaker ratings, fuse characteristics)
- Load levels and system operating conditions

- **Key outputs:**

  Fault current magnitudes at key points in the network

  - Relay and breaker response times for various fault conditions
  - Identification of equipment stress risks
  - Recommendations for protection coordination adjustments
  - Impact assessment of new DER/IBR interconnections on fault behavior

Phasor-Domain/Transient Simulations

- **Scope:** Positive-sequence dynamic simulation, also known as phasor-domain simulation, is a computational method used to model the dynamic behavior of electric power systems under steady-state and transient conditions. It simulates the system's voltages and currents by representing them as phase vectors, or phasors, which capture the magnitude and phase angle of alternating sinusoidal currents. Mathematically, phasor-domain simulation involves solving a set of nonlinear algebraic equations derived from Kirchhoff's laws, like ACPF, but in this case, it considers the power frequency dynamic responses of the system over time. These simulations are used to perform power system stability analyses.
- **Scale:** A phasor-domain simulation typically applies to large-scale interconnected power systems with complex generation, transmission, and load dynamics.
- **Horizon:** The simulation typically covers time periods of less than one minute, analyzing system responses to disturbances and subsequent recovery. In the case of dynamic voltage stability simulations, these simulations may extend well past a minute to capture the restorative behavior of demand and slower voltage-controlling devices, such as load-tap changers.

INDUSTRY SPOTLIGHT

Classification of Stability

"Traditional power systems are susceptible to three broad types of stability classifications: voltage stability, which is the ability to maintain steady voltages following a disturbance; frequency stability, the ability to respond to frequency deviations and return to stable operating conditions after a disturbance; and rotor angle stability, the ability to maintain synchronization across the system following a disturbance."

Hatziargyriou et al. (2021)

- **Action:** Determination of stability performance informs operational decision-making, assessments of system reliability, and evaluation of the impacts of planned system upgrades. It helps prevent cascading failures, optimizes system performance, and ensures system compliance.
- **Key inputs:**
  - Power system network model (bus locations, line parameters, generator characteristics)
  - Initial steady-state conditions (bus voltages, power flows, generator operating points)
  - Dynamic models of system devices including, but not limited to, generator and storage characteristics, voltage and frequency control systems, protection systems, and loads
  - System disturbances such as load fluctuations, generator trips, and faults
  - Protection system configurations and zoning, for meaningful identification of contingency locations, resultant clearing times, and cascading events
- **Key outputs:**
  - Time series data on bus voltages
  - Generator rotor angles
  - System frequency variations
  - Active and reactive power flows
  - Damping characteristics of oscillations

Electromagnetic Transient Simulations

- **Scope:** Also known as waveform modeling, EMT is a high-fidelity computational method to analyze the fast-changing electrical transients that occur in power systems. Unlike phasor-domain simulations, which assume sinusoidal steady-state conditions, EMT simulations solve the full time-domain differential equations governing the unbalanced, instantaneous voltages and currents in a power system. Mathematically, EMT simulation is based on solving differential equations derived from Kirchhoff's voltage and current laws using numerical integration techniques. This approach provides a highly detailed view of system behavior, making it important for studying fast transient phenomena such as switching surges, lightning strikes, protection system operation, power quality and harmonics, and, more recently, system response involving power electronics.
- **Scale:** The model applies to detailed studies of localized power system components (e.g., transformers, circuit breakers, power electronic devices) as well as larger systems incorporating IBRs, high-voltage DC systems, and flexible AC transmission systems (FACTS). It is suited for "resonance-driven and converter-driven" stability analysis (Hatziargyriou et al., 2021).
- **Horizon:** EMT simulations operate on very short time scales, typically in the microsecond to millisecond range, capturing fast electromagnetic transients in power systems.
- **Action:** The model informs power system design, protection coordination, transient stability assessment, insulation design, power electronics integration, and validation of system component performance under fast-changing conditions.
- **Key inputs:**
  - Detailed network model (lines, transformers, generators, power electronic converters)
  - Generator and storage control system models
    - Generator elements: exciter, governor, turbine, etc.
    - Inverter controllers: current, voltage, power, etc.
    - Plant internal protection schemes
  - External disturbances (e.g., lightning strikes, breaker operations, load fluctuations, component loss/failure)
- **Key outputs:**
  - High-resolution time-domain waveforms of voltages and currents
  - Fault transients and switching overvoltages
  - Power electronic switching behavior
  - Power quality and harmonics

Analytical Approaches

To assess a range of operating conditions, transmission planners apply a variety of analytical frameworks depending on the type of system stress being assessed, using the domains discussed above.

Contingency Analysis

Contingency analysis checks the steady-state response of an operating condition (N-0, where N refers to a normally configured, stable operating point and does not necessarily mean that all elements in the system are online) following the loss of a single (N-1), or multiple (N-2, etc.), components such as generators, transmission lines, or transformers by re-solving the power flow equations with the component(s) removed. The integer value refers to the quantity of components removed from service for that particular contingency. The purpose of this analysis is to identify components that may be overloaded or outside of acceptable voltages following the loss of one or more components, which may indicate that the system is not secure in that operating condition. This overload in an actual operating condition would likely precipitate a protection response that would remove the overloaded component from operation and potentially trigger a cascading failure. Often, a set of credible[5] contingencies is assessed instead of applying this analysis to every component in a power system. To check for cascading failure, an N-K approach is taken, in which

5 Here, the term "credible" indicates a contingency that is known to have a severe impact and potentially interrupt power delivery and whose occurrence is more likely than others. Typical credible contingency candidates are the disconnection of the largest generator or the outage of a heavily loaded transmission line. Many systems have additional, uniquely defined credible contingencies.

overloaded components are sequentially removed and the power flow equations are solved once more.

Voltage Stability Assessments

The voltages on the transmission system must always be maintained within acceptable limits, for both the contractual delivery of power and the stability of the system itself. Due to the nonlinear nature of ACPF, factors like transmission line loading, demand power factor, and the reactive power behavior of generators and support devices can affect system voltages in complex and sometimes counterintuitive ways. Steady-state voltage stability assessments involve the generation of PV (active power-voltage) and QV (reactive power-voltage) curves using modified steady-state power flow solvers. These curves provide insight into the reactive power needs and the proximity of the system to loadability limits, both at initial conditions and following component losses. These loadability limits, known as bifurcation points, are a critical point in system operation, where past that point the system is susceptible to collapse. Dynamic voltage stability assessments typically consist of a sequence of steady-state analyses that investigate the voltage impacts of changing reactive power consumptions. Some recent developments include incorporation of transient performance considerations into traditional steady-state PV analysis, allowing for determination of loadability limits that are rotor- and voltage stability–constrained (Richwine et al., 2023).

Short-Circuit Analysis

When a short circuit occurs—an unintended path to ground that is also known as a fault—currents much larger than normal operation may be delivered by nearby generators, greatly increasing the current on connecting transmission lines and transformers. Short-circuit analysis allows planners to determine these currents. To obtain the most detailed understanding of the fault currents and respective unbalance in the network requires full network information, including phase connectivity and individual conductor characteristics. Understanding the current magnitudes and duration is important for selecting equipment and coordinating protection systems, the operation of which may be affected by lower-than-expected fault current magnitudes. Changing generation mixes can have a large impact on current magnitudes, as can adjustments in system topology through system upgrades, or simply increased capacity factors of transmission systems. Recently, short-circuit analysis has also been used as a stability indicator for the interconnection of IBRs, where regions of lower short-circuit ratios may present conditions that lead to the unstable operation of IBRs (NERC, 2017).

Small-Signal Stability

A power system in a steady state will remain in that state only if all the component controllers are tuned, such that any small deviation will be met by an automatic response that brings the system back to steady state. Small-signal stability analysis techniques investigate this characteristic of power systems by linearizing differential equations describing the response of all relevant components and applying linear algebra theory to determine system stability. The system's steady-state conditions will be taken from a solved power flow. Because this method does not involve time-domain simulations, it is far less computationally expensive. However, it does not provide answers to the dynamic response to large impacts such as line losses or generator trips.

With a changing generation mix and higher shares of IBRs, this method is becoming more popular as a screening tool to identify system conditions/snapshots for detailed stability assessment in EMT. The impedance scanning approach is an adjacent screening-type analysis showing promise for assessing the stability of IBR dominated systems (Shah et al., 2021).

Transient (Large-Signal) Stability

Transient (large-signal) stability is evaluated by a variety of approaches that generally involve time-domain simulations to assess the system's response to large impacts, where contingencies such as component losses or short circuits are applied, and the dynamic response of all elements in the system is observed to determine whether the system returns to steady state. In traditional power systems dominated by synchronous generators, phasor-domain simulations were sufficient to assess the electromechanical stability of systems of most sizes. These would be used to determine critical clearing times for faults, primary response characteristics of generation (especially in the context of reduced mechanical inertia leading to higher rate of change of frequency (RoCoF) with more IBRs), and necessary load-mitigating control (such as under-frequency load shedding). Fault-induced voltage recovery is another key dynamic concern, especially with potential exacerbations due to IBRs (Kenyon and Mather, 2020). The increase in IBRs results in an increase in controllers and power electronic switches that interact with power system elements at smaller time scales than electromechanical elements that were traditional stability drivers. Because these faster dynamics are not effectively captured with phasor-domain tools, EMT simulations are being used more often to assess system stability.

Traditional Planning Scenarios

Planners use these modeling tools and heuristics to test system performance under different conditions and ensure compliance with industry standards. Since system conditions fluctuate continuously, and a full system assessment of all operating conditions is impractical from a human resource and computational cost perspective, certain conditions are selected for study. Historical best practices suggest that reliability can be assessed by focusing on a few key scenarios, such as:

- Seasonal system peaks (e.g., highest demand periods)
- Seasonal minimum loads (e.g., lowest demand periods)
- High wind/variable energy resources (e.g., solar photovoltaic)
- Low wind/variable energy resources (e.g., solar photovoltaic)

As the system evolves and faces unprecedented conditions, the assumption that modeling a handful of "standard" scenarios within transmission is breaking down. There is an emerging case for integrated transmission planning in order to expand the scenarios studied and their impact across the other planning areas.

Overview of Distribution Planning

General Responsibilities and Decisions

The distribution network, which consists primarily of radial networks operating at voltages typically below 35 kV, delivers electricity to individual homes, businesses, and other end users, ensuring that it is safely delivered at usable levels. Table 4 presents the scope, scale, horizon, and action related to distribution planning.[6]

TABLE 4

Distribution Planning: Scope, Scale, Horizon, and Action

Scope	Distribution planning focuses on designing, managing, and maintaining lower-voltage networks that connect end users to the larger power system. Planners ensure that distribution circuits can handle varying customer loads while maintaining deliverability and reliability. This includes sizing equipment, assessing system stress, ensuring power quality, and tracking performance using industry reliability metrics. Distribution planners assess the loading of these distribution systems, and customer behavior is typically aggregated for planning purposes.
Scale	Distribution planning focuses on specific local feeder networks, substations, and service areas in cities, towns, and rural areas. Some plans address simple radial circuits serving a handful of customers while others deal with complex networks spanning many miles, incorporating overhead and underground lines, voltage regulation equipment, automated controls, and intricate protection schemes.
Horizon	The utility's long-term utility capital plan provides a roadmap for distribution investments over a 1- to 10-year period. The plan anticipates future trends, such as locations of new load growth (including new neighborhoods or commercial/industrial areas), increased electrification, and DER integration, to ensure long-term grid adaptability. The capital plan informs near-term infrastructure needs, typically identified in an annual planning process. The annual plan also establishes maintenance schedules and forecasts demand growth.
Action	Distribution planning informs decisions related to network expansion, equipment installation, and reliability improvements. Planners provide insights that guide investments such as new substations, feeder reinforcements, and voltage regulation solutions to accommodate changing customer loads. A key aspect of this process involves tracking system performance using industry-standard reliability metrics, such as SAIFI (System Average Interruption Frequency Index) and SAIDI (System Average Interruption Duration Index). These metrics help planners identify areas where maintenance or upgrades are needed to improve service continuity. Their analyses support infrastructure development, regulatory compliance, and cost management strategies.

Source: Energy Systems Integration Group.

6 Berkeley Lab's integrated distribution planning website provides additional information: https://emp.lbl.gov/projects/integrated-distribution-system-planning.

Modeling Domains

Traditionally, simulation tools for distribution system analyses have used a wide range of modeling fidelities, ranging from spreadsheet-based estimates with trusted semi-manual heuristic techno-economic designs to detailed physics-driven engineering simulations that capture phase voltages, currents, and system performance under various loading conditions. In this context, unbalanced AC power flow (UACPF) and short-circuit/fault modeling are essential tools for identifying potential system violations and guiding network expansion. There are also increasing efforts to incorporate some advanced approaches that begin to mirror planning processes more commonly used for the bulk power system, such as optimization-based capacity expansion and use of UACPF for time series operations.

Unbalanced AC Power Flow

- **Scope:** UACPF refers to the simulation of power flow within an electrical system where the three phases do not carry equal loads or experience identical conditions. Unlike balanced ACPF, which assumes uniformity across phases, unbalanced power flow accounts for phase-specific variations in voltages, currents, and power flows. These imbalances arise due to asymmetrical loading, uneven phase distribution, and conductor orientation, making UACPF analysis crucial for accurately representing real-world grids. Mathematically, unbalanced power flow involves solving a more complex set of nonlinear equations than for ACPF. UACPF equations model each phase individually, capturing their distinct voltages, currents, and power flows, as well as inter-phase interactions, adhering to Kirchhoff's laws. These models also include careful simulations of voltage control devices such as regulators, capacitors, tap changing transformers, and advanced inverter controls. UACPF is particularly important for North American–style distribution system analysis where it is common to have a portion of the system with only single-phase connections (e.g., "laterals").
- **Scale:** The model is primarily applied at the distribution system level, including medium-voltage networks, microgrids, and systems integrating rooftop solar, electric vehicles, and other DERs. In some cases, the low-voltage connections to customers are also modeled (these are commonly referred to as secondaries, which are connected with service transformers), particularly for more extensive low-voltage systems such as those found in dense urban areas (e.g., meshed secondary networks) and European-style systems.
- **Horizon:** The analysis can be performed as a single steady-state snapshot or as a time series simulation to model interactions between time-varying loads, generation, storage, and control schemes. Steady-state snapshots at peak loading have historically been the most common approach.
- **Action:** The model informs distribution system investments, power quality assessment, energy delivery optimization, voltage regulation design, mitigation of phase imbalances, and identification of necessary system upgrades.
- **Key inputs:**
  - System topology (network structure and connections, often including switching arrangements for different operating conditions)
  - Phase-specific line impedances and configuration
  - Load and generation data for each phase
  - DER-specific information (e.g., rooftop solar, electric vehicles), including advanced inverter control settings
  - Voltage setpoints and system constraints (e.g., voltage limits, current ratings)
  - Equipment control settings (e.g., regulators, capacity controls, tap-changing transformers, shunt capacitors)
- **Key outputs:**
  - Phase-specific voltages (magnitude and angle)
  - Active and reactive power flows per phase
  - System losses
  - Thermal loading information on all elements
  - Identification of steady-state power quality issues and phase imbalances
  - Control operations for utility equipment and DERs

UACPF also serves as a foundation for a wide range of other distribution analyses, including hosting capacity analysis, evaluation of non-wires alternatives, interconnection studies, and assessment of voltage control strategies, including determining advanced inverter settings. UACPF is also used to complement bulk-system simulations, such as to reflect aggregated distribution and DER operations to support production cost or stability analyses.

Short-Circuit/Fault Modeling

See the discussion of short-circuit and fault modeling in the transmission planning section above.

Traditional Planning Scenarios

In the past, distribution planners investigated only the peak loading of the system, often considering heuristics such as simultaneity factors to estimate what fraction of the sum of individual loads would be expected to contribute to this peak. This worked historically because systems were primarily radial, operated at a lower voltage, and typically experienced only unidirectional power flow (from the feeder head to the consumer). This meant that the stressed operation occurred at peak demand, and some of the more nuanced stability constraints observed at the transmission level were not present. The peak scenarios were typically forward-looking in order to estimate load growth and to incorporate the different timing of investments as the system changed to accommodate different loads and devices. Short-circuit analysis was also applied to a variety of operating conditions to assess the fault current availability for protection coordination.

With the increasing integration of DERs, particularly storage and electric vehicles, planning scenarios increasingly consider multiple loading conditions. For instance, some hosting capacity analyses and flexible interconnection studies consider full 8,760 hourly profiles or representative hourly weekday and weekend time series for each month of the year. Similar approaches can also be used to understand the value of integrated control systems such as advanced distribution management systems (ADMS) or DER management systems (DERMS).

Overview of Planning for Customer Loads and Resources

General Responsibilities and Decisions

Customers, seen solely as the recipients of electricity in the past, are now increasingly active power system participants, both in shaping load and providing behind-the-meter generation and storage. Customer DERs commonly participate in utility retail programs and, in some regions, wholesale electricity markets. Table 5 (p. 22) presents the scope, scale, horizon, and action related to planning for customer loads and resources.

Planning for customer loads and resources includes the following:

- **DER programs:** Develop and manage DER programs such as incentives and rate designs for load flexibility, battery storage, and electric vehicle charging that align with state requirements, customer needs, and utility plans
- **Rate design:** Design and implement rate structures like time-of-use pricing and demand charges, which reflect the cost of electricity consumption at different times and encourage changes in energy usage and demand to help maintain reliability and energy affordability
- **Customer engagement and education:** Conduct research to understand customer preferences, barriers to adoption, and opportunities for improved communication, and apply lessons learned to outreach strategies for programs and rate designs
- **Compliance:** Meet state and federal requirements, as relevant, and secure approval from regulators or boards
- **Data analysis and performance monitoring:** Use load forecasting and modeling to predict program impacts, track adoption rates, measure energy impacts, and align with grid modernization investments (e.g., advanced metering infrastructure) to enhance data-driven decision-making
- **Stakeholder collaboration:** Engage third-party service providers, state agencies, regional organizations, and local organizations to help foster success

TABLE 5
Customer Planning: Scope, Scale, Horizon, and Action

Scope	Planning for customer loads and resources involves designing and implementing retail programs and pricing that empower customers to make informed energy choices while supporting system reliability and affordability. This includes developing demand-side management strategies, distributed solar and storage programs, and rate structures that give customers the opportunity to adjust energy consumption and production to help meet grid needs. Implementation includes regulatory compliance, customer education, and analyzing program performance and rate offerings. Unlike generation, transmission, or distribution planning, which focus on physical infrastructure, planning for customer loads and resources is centered on designing or creating behavioral and financial incentives that shape energy consumption patterns and is typically distributed across multiple teams, with responsibilities varying by utility.
Scale	Planning for customer loads and resources involves a wide variety of scales, from individual households to large industrial and commercial customers. Some energy efficiency, demand response, and behind-the-meter generation programs and rate designs target specific customer classes, such as residential or industrial. On a broader scale, planning may involve state-wide or regional efforts to improve energy efficiency, integrate DERs, promote economic development, or enhance demand flexibility.
Horizon	Customer planning typically works on short- to medium-term time horizons, with programs designed to deliver measurable impacts within a few years. For example, short-term initiatives might include programs for smart thermostats or incentives to shift the timing of electric vehicle charging. Longer-term strategies focus on market transformation and wide-scale adoption of new technologies over a 5- to 10-year period.
Action	Planning for customer loads and resources informs key decisions related to program design and rate structures. Planners analyze data and monitor performance to track adoption rates, note changes in energy usage and demand, and refine strategies. Additionally, planning supports broader utility objectives, such as peak demand reduction and grid modernization.

Source: Energy Systems Integration Group.

Modeling Domains

Planning for customer loads and resources relies on various modeling domains to analyze energy usage trends, evaluate program and rate impacts, and develop strategies. These domains help assess demand patterns, financial viability, and customer behavior, enabling more effective planning. Traditionally, model outputs have also provided key inputs for other modeling domains, such as providing load and DER forecasts for generation and distribution planning.

While many of these models are quantitative, customer planning often incorporates a range of modeling approaches. Some models rely on historical trends, econometric estimates, and machine learning techniques, while others use scenario-based planning or expert judgment to account for uncertainties in customer behavior, technology adoption, and policy shifts. Qualitative assessments and stakeholder input play a role in shaping program design and modeling inputs, assumptions, and approaches. The diversity of modeling approaches allows customer planners to balance technical rigor with flexibility. The following outlines some types of models used.

Load Forecasting Models

- **Scope:** Predict customer energy consumption, peak demand trends, and adoption of DERs
- **Scale:** Can be applied at various levels, including individual customers, feeder-level, regional grids, or nation-wide
- **Horizon:** Range from short-term (hourly/daily) to medium-term (monthly/yearly) and long-term (decades ahead)
- **Action:** Help design DER programs and rate designs
- **Key inputs:**
  - Historical energy consumption data
  - Weather patterns and forecasts
  - Economic indicators (e.g., gross domestic product, employment)

- Customer demographics and behavioral trends
  - DER adoption forecasts
  - Policy and regulatory changes
- **Key outputs:**
  - Predicted energy demand profiles (hourly, daily, seasonal, annual)
  - Peak demand forecasts
  - Expected growth or decline by customer segment
  - Impact assessments of DER adoption and electrification trends

Rate Design and Tariff Models

- **Scope:** Analyze cost-of-service, customer bill impacts, and alternative rate structures (e.g., time-of-use pricing, dynamic pricing, demand charges)
- **Scale:** Can apply at the level of an individual customer, a customer class (residential, commercial, industrial), or system-wide
- **Horizon:** Typically medium to long term (multi-year tariff adjustments, regulatory review periods)
- **Action:** Assess fairness of rate structures; evaluate price signals for customer participation in demand-side management and other DER programs
- **Key inputs:**
  - Utility cost structures (generation, transmission, distribution, customer service points)
  - Load profiles of different customer segments
  - DER adoption rates
  - Historical billing data and customer responses to past pricing changes
  - Policy and regulatory constraints
- **Key outputs:**
  - Estimated customer bill impacts under different rate designs
  - Cost recovery assessments for utilities
  - Price elasticity effects on energy consumption
  - Recommendations for new rate structures

Demand Response and Demand-Side Management Planning Models

- **Scope:** Estimate potential load reductions from demand response programs and assess customer participation in demand-side management initiatives
- **Scale:** Can apply at the level of an individual appliance, household, commercial facility, or system-wide
- **Horizon:** Typically short to medium term (hourly event dispatch to multi-year program evaluation)
- **Action:** Evaluate program effectiveness in reducing and shifting peak demand; assess potential for and barriers to customer participation
- **Key inputs:**
  - Customer load profiles
  - Historical data on demand response event performance
  - Behavioral response models
  - Grid conditions and peak demand forecasts
  - Technology availability (e.g., smart thermostats, direct load control, automated demand response systems)
- **Key outputs:**
  - Estimated load changes by customer segment
  - Forecasted participation rates
  - Cost-benefit analysis of demand response programs
  - Grid reliability and capacity savings impacts

Cost-Effectiveness Tests

- **Scope:** Evaluate the cost-effectiveness of customer programs, considering costs, customer savings, and utility revenue impacts
- **Scale:** Applied at project, program, utility, or regional market levels
- **Horizon:** Typically medium to long term (multi-year financial impacts)
- **Action:** Conduct economic evaluation of customer programs; assess potential incentive and rate structures

- **Key inputs:**
  - Program implementation costs (capital, operational, administrative)
  - Customer participation and response rates
  - Avoided infrastructure investment costs
  - Energy and ancillary service price forecasts
  - Discount rates and financial assumptions
- **Key outputs:**
  - Net present value, payback periods, and internal rate of return
  - Cost-effectiveness metrics (e.g., total resource cost test, participant cost test)
  - Sensitivity analysis on program assumptions
  - Long-term financial impacts on utility revenues

Customer Behavior and Adoption Models

- **Scope:** Forecast customer participation in DER programs and new rate structures based on historical data, market trends, and behavioral economics
- **Scale:** Applied at the individual customer level, customer segment level, or across an entire utility service territory
- **Horizon:** Short to long term, depending on the technology adoption curve and behavioral response time frame
- **Action:** Evaluate incentives and rate structures to drive customer participation and response
- **Key inputs:**
  - Historical customer participation data
  - Market trends for new energy technologies
  - Behavioral economics insights (e.g., price elasticity, social influences)
  - Survey and demographic data
- **Key outputs:**
  - Forecasted adoption rates of program measures and new or modified rate structures
  - Customer segmentation insights
  - Sensitivity analysis on program participation under different incentive structures

The Siloed State of Planning

Historically, the functions of each planning area have operated in relative isolation, each supported by distinct data, models, and software tailored for specific parts of the electricity system. While this siloed approach reflected the original needs of separate business functions, today's grid challenges cut across these boundaries, highlighting the need for integrated planning. Yet, whether by design or inertia, fragmentation remains. As the pace of change accelerates, the industry is confronting these disconnects—in communication, data, modeling, and software—to effectively coordinate planning efforts. The next chapter outlines how utilities, system operators, and others can begin this alignment, offering targeted entry points based on their current stage of planning integration.

The Integrated Planning Framework

Once planners have a clearer understanding of the context surrounding their planning areas and modeling domains, as outlined in the previous chapter, they are well positioned to strengthen or expand their integration efforts. Expanding integrated planning offers enhanced reliability, reduced costs, and improved coordination across the power system planning. A detailed discussion of these benefits is given in the following chapter.

This chapter introduces a practical framework for integrated planning, recognizing that integration exists on a spectrum. Whether an organization is just starting out or isrefining a mature approach, different levels of integration can offer distinct and valuable benefits.

Stages of Integrated Planning: A Walk-Jog-Run Approach

The desired level of planning integration across generation, transmission, distribution, and customer loads and resources may vary based on the specific needs and organization of the utility, system operator, or other system structures. The framework presented here grew out of discussions around potential best practices for integrated planning among participants in the ESIG Integrated Planning Task Force, a group including electricity planning experts from utilities, regional system operators, national laboratories and other research organizations, software vendors, consultants, and other practitioners. The guidebook serves as a practical entry point that meets planners where they are. To address the diversity of planning organizations and their objectives, some in the industry adopt a "walk-jog-run" approach to integrated planning (U.S. DOE, 2020; Xcel Energy, 2021; Keen et al., 2023; Burdick et al., 2024). This staged framework provides a practical roadmap for advancing integration efforts while ensuring that progress is sustainable and effective. We begin by defining the walk-jog-run construct as `used in this guidebook and starting from the simplifying assumption that individual planning areas are already up to date with industry best practices.

Walk: Communication, Trust, and Understanding

The foundation of integrated planning is fostering communication and a shared understanding among planners in different areas. At the *walk* stage:

- Planners gain a core understanding of the various, distinct planning processes and how they intersect with their own planning area. Specifically, grasping how these planning processes "hang together" is a primary objective at this stage.
- Effective communication improves trust and reveals the importance of interconnected components and processes.
- Language is aligned so that planning areas are using the same terms to mean the same things, particularly for those terms that currently have different meanings depending on the planning area—for example, scenario, sensitivity, or capacity.
- Shared objectives are acknowledged, even though they may manifest differently across planning areas. With this as a basis, a meaningful gap assessment can be executed.
- Change management principles are implemented to create a strong foundation for successful advanced integration stages.
- Stakeholders play a key role, even if they may not fully understand cross-planning complexities. Early engagement enhances collaboration.

The *walk* stage emphasizes the importance of building relationships and aligning motivations.

The *walk* stage emphasizes the importance of building relationships and aligning motivations. Significant breakthroughs in integration can be made by hiring planners with expertise across power planning areas—or across power planning and system operations—and establishing collaborative platforms for communication. However, these personnel-driven breakthroughs are often challenging to achieve. Deep expertise in even one planning area takes years to develop, making it difficult to find individuals with broad, cross-cutting experience. A more practical near-term approach is to foster collaboration between specialists in different domains and provide structured opportunities for knowledge exchange, rather than relying solely on individual expertise to bridge gaps.

INDUSTRY SPOTLIGHT

A Customer Planner Emphasizing Trust During the *Walk* Stage

"At times, I have observed a poor trust basis between customer and grid planners stemming from a lack of communication. A first step to address these trust issues is improving communication channels to promote better understanding about the relevant objectives and constraints (whether physical or customer based) within each planning area."

Jog: Aligning Data and Assumptions

Once foundational communication is established, the *jog* stage involves centralizing and aligning data inputs, sources, and assumptions, including:

- Identifying data used in multiple domains as well as outputs from one modeling domain used as inputs in others
- Streamlining data-sharing processes to ensure consistency across planning areas and their modeling domains

INDUSTRY SPOTLIGHT

An Integrated Planner Highlighting the Importance of the *Walk* Stage

"The value of the *walk* stage should not be underestimated. It is a core first stage to integrated planning. Although this stage is not technical, it is where we have seen most of the friction between planning areas. It is critical to understand the objectives, modeling activities, and study assumptions of one's planning counterparts. There's also an element of change management at this stage, which must be addressed prior to effective *jog* and *run* stages."

- Identifying and correcting misaligned assumptions—often a result of siloed data curation
- Collaborating with a focus on creating shared datasets that reflect overlapping objectives while respecting unique planning area requirements

See the chapter "Overview of Electric Power System Planning: Structured Across Consistent Dimensions" for guidance on the general inputs, assumptions, and outputs of planning areas and modeling domains.

The *jog* stage lays the groundwork for deeper integration by ensuring that all stakeholders are working with consistent, accurate, and contextually relevant data.

Run: Integrated Modeling and Execution

The final, *run* stage is the culmination of the framework, where the interconnected approach of integrated planning is fully realized, enabling actionable trade-offs and cohesive decision-making across planning areas. The full execution of integrated planning is achieved through coordinated modeling efforts:

- Model runs are coordinated, drawing on the success of the communication and data alignment phases.
- Initial efforts may involve running open-loop models to observe the impact of integration or conducting rapid iterations to evaluate how constraints in one planning area influence objectives in another.
- After constraining factors are better understood, these validated feedback mechanisms may then evolve into more comprehensive co-optimization.

- Coordinated modeling results provide valuable insights that guide further refinement and solidify the long-term benefits of integrated planning.

The remainder of this chapter explores in detail the application of this framework for various planning area interfaces. See "The Value of Integrated Planning" chapter for a discussion on the value proposition of these integrations.

While successful integrated planning does not require collaborating planners to work for the same entity (e.g., utility or system operator), we make that simplifying assumption for this guidebook. The purpose of this simplification is to exclude challenges related to different corporate structures, such as data security, communication barriers, and misaligned objectives. While these challenges are real, they fall outside the scope of this framework. Additionally, the following discussions are designed to be broad enough to remain relevant across diverse business cases.

Integration of Generation and Transmission Planning

Technology changes at all levels of the power system introduce new analytical challenges for generation and transmission planning. The following are standard objectives for these planning areas:

- Affordable energy supply and delivery
- Reliability and stability of the bulk power system in steady state and under credible contingencies
- Sufficient flexibility to address variability in supply and demand, considering the range of possible outcomes based on scenario analyses
- Sufficient capacity of generation and transmission, explicitly considering all types of technologies—demand- and supply-side—to meet loads and ancillary requirements at all times

The determination of "sufficient" flexibility is driven by the need to accommodate a range of potential degrees of variability and uncertainty that can stem from both supply (e.g., renewable generation) and demand (e.g., transportation electrification), considering all sources of flexibility. In short, more diverse technologies and operating conditions require more comprehensive approaches to assess reliability and stability impacts, considering affordability and investment needs.

A more coordinated approach helps ensure that investment decisions account for interdependencies between generation and transmission planning, optimizing infrastructure deployment and avoiding unnecessary costs.

A more coordinated approach helps ensure that investment decisions account for interdependencies between generation and transmission planning, optimizing infrastructure deployment and avoiding unnecessary costs. Historically, the planning approaches for these areas—load duration curve for generation and peak demand assessments for transmission—have been relatively static. Integrated generation and transmission planning brings the operation of these systems closer to the planning process to more accurately assess the growing diversity in system needs for flexibility, reliability, and affordability.

Walk

The first step in integrating generation and transmission planning is to establish a common understanding of reliability requirements. Planners in both areas execute processes to ensure sufficient capacity to meet peak demand. Beyond that, responsibilities are split: generation planners primarily focus on energy requirements, and transmission planners focus on delivery and stability requirements by assessing specific operating conditions. Integrating the processes of these teams to address all requirements in a comprehensive manner begins with understanding each other's activities.

What Transmission Planners Need to Understand About Generation Planning

- Location, capacity, and expected dispatch of existing generation and storage assets are derived from economic optimizations that simplify many practical constraints. Equally important is the location and forecasted consumption of demand.
- Potential interconnection location of planned generation projects comes with uncertainty. For example, for

generic new wind and solar resources, capacity expansion models often do not assume a specific location. Instead, a generic interconnection cost adder is included in the resource cost.

- Future dispatch conditions that may stress the transmission system are not easily identified within the generation process alone.
- Terminology: In the context of generation planning, "scenarios" are model runs with a specific set of input assumptions and constraints, including plausible conditions for resource costs, such as elevated natural gas prices. Scenarios aim to capture the breadth of plausible futures.

What Generation Planners Need to Understand About Transmission Planning

- Transmission constraints can impact the operation of generation and storage assets in substantial and, at times, counterintuitive ways.

INDUSTRY SPOTLIGHT

TVA's Integrated Transmission/Generation Planning Process Requires Regular Communication

"[TVA's] generation/transmission interface follows an annual schedule. It usually starts in the spring with a capital investment plan [generation/transmission build-out] that follows a mid-year update after considering changes in the macro economy as well as internal conditions. From this point, it takes approximately four months for the company to develop its initial resource plan, inclusive of gathering data, running models, analyzing outputs, and revising inputs and re-running scenarios. During this time, the transmission planning team is involved in a portion of the process, as well. The outputs of the resource planning models are provided to the transmission planning team, which then initiates a four- to five-month transmission planning process to coordinate with stakeholders, gather inputs, evaluate results from the resource plan, build transmission models, run the transmission studies, and then coordinate on results. Ultimately, this annual process results in a roadmap that identifies the projects the company will propose to undertake. Finally, the planning teams coordinate with finance to ensure that investments in capital projects are aligned with the company's long-term strategy."

EPRI (2022), p. 34

- Detailed analysis generates large computational workloads and substantial manual efforts, which means a detailed reliability assessment of every possible future operating condition can be prohibitive.
- Terminology: In the context of transmission planning, "scenarios" typically mean different operational situations handled with the same generation portfolio, aimed at a period of expected system stress. In contrast to representing the breadth of future conditions for generation planning, scenarios for transmission planning aim at depth.

Jog

The integration of generation and transmission planning processes requires bridging the gap between economic optimization models and physical simulation models. In particular, generation planners need to provide viable operational conditions using a PCM optimization for transmission planners to meaningfully assess the operation of the system in those conditions with their ACPF-based tools. Because of the fundamental simplifications of the PCM tool, ACPF can observe certain system intricacies that a PCM simply cannot. In those parts of the country that have IRP processes, the generation portfolio and transmission asset build-out selections may be the result of a co-optimized generation/transmission IRP process, where some basic transmission constraints are handled with capacity expansion constraints.[7] This enables transmission planning studies that are aligned with the planned or proposed generation assets. It also can allow generation planning studies to capture the physical constraints of the power grid.

Aligning Electricity System Assets: Two Solutions for Bridging PCM and ACPF

- **Option 1:** The generation planning team can increase the granularity of transmission representation in generation planning models to be aligned with the level of detail in a transmission model. For instance, a nodal PCM represents every transmission bus of the network being modeled. This modeling approach allows a more robust exchange of constraints, because more details of constraints uncovered by the transmission analyses can be fed back to the optimization tool

7 See ESIG's companion report, *Foundations of Integrated Electricity Planning*, for additional details (ESIG, 2025a).

(e.g., unexpected must-run constraints or voltage stability–driven loadability constraints that DC power flow approximations of a PCM do not uncover). In short, the operational realities of the proposed fleet can be specifically determined. However, this approach can add considerable computational requirements to the PCM model, which may not provide sufficient value depending on the scenarios under study. Depending on the type of transmission constraints identified, they may be used to inform nodal capacity expansion models. While not yet common, this method can support effective early-stage siting of generation units, which is a necessary input for a nodal PCM.

- **Option 2:** Assets can be mapped from generation planning models to transmission planning models without a one-to-one bus mapping. In this case, PCM optimizations will be less capable of directly capturing some of the operational constraints uncovered in transmission studies, such as specific transmission corridor loading. Mapping assets from generation to transmission planning models also requires: (1) defining zones to adequately capture changing patterns of congestion, (2) defining limits on flows between zones, and (3) translating zonal results to nodal inputs. Constraints on zonal models may result in inefficient utilization of transmission systems, but innovative approaches may mitigate these inefficiencies.

Time Series Approach for Transmission Studies

In theory, generation planners can provide chronological dispatches to transmission planners to enable an 8,760 analysis and uncover any at-risk operating conditions, considering the expected power flow and reserve units. In practice, however, such a comprehensive analysis may not be possible due to computational constraints. Even the least computationally intensive analysis for steady-state N-1 contingency for a full year would be resource-intensive. At the same time, implementing such a framework facilitates an easier identification and selection of potentially stressed system operating conditions that deviate from the traditionally selected scenarios.

Effective Feedback Mechanisms

To close the integrated planning loop, it is critical to characterize in generation optimization models the operational constraints uncovered by transmission planners. This is the optimal alignment between the generation and transmission planning processes, which allows the integrated planning approach to appraise the operational constraints of the generation fleet and transmission network under inspection. Practical investment options that mitigate these constraints can be assessed in conjunction with the estimated operational costs of these constraints were they not addressed. This enables a comparison of costs between the two system plans, and generation planners can run new scenarios in capacity expansion processes to reflect transmission planning findings.

The feedback of constraints to generation planners in an iterative fashion is very important. Some constraints are simple, such as must-run characteristics of reactive power source generation units near load centers. Others can be more complex, such as transfer path limits that can depend on a variety of system conditions, including the commitment of key generators and associated ramping capabilities, interregional inertia levels that drive resultant angle stability constraints, frequency reserve requirements based on system inertia levels, and voltage stability considerations driven by reactive power availability.

INDUSTRY SPOTLIGHT

An Integrated Planning Expert on the Importance of Multiple Iterations

"The notion of iterative feedback should be included here. We often won't get it fully optimized in one loop around. Iteration is important."

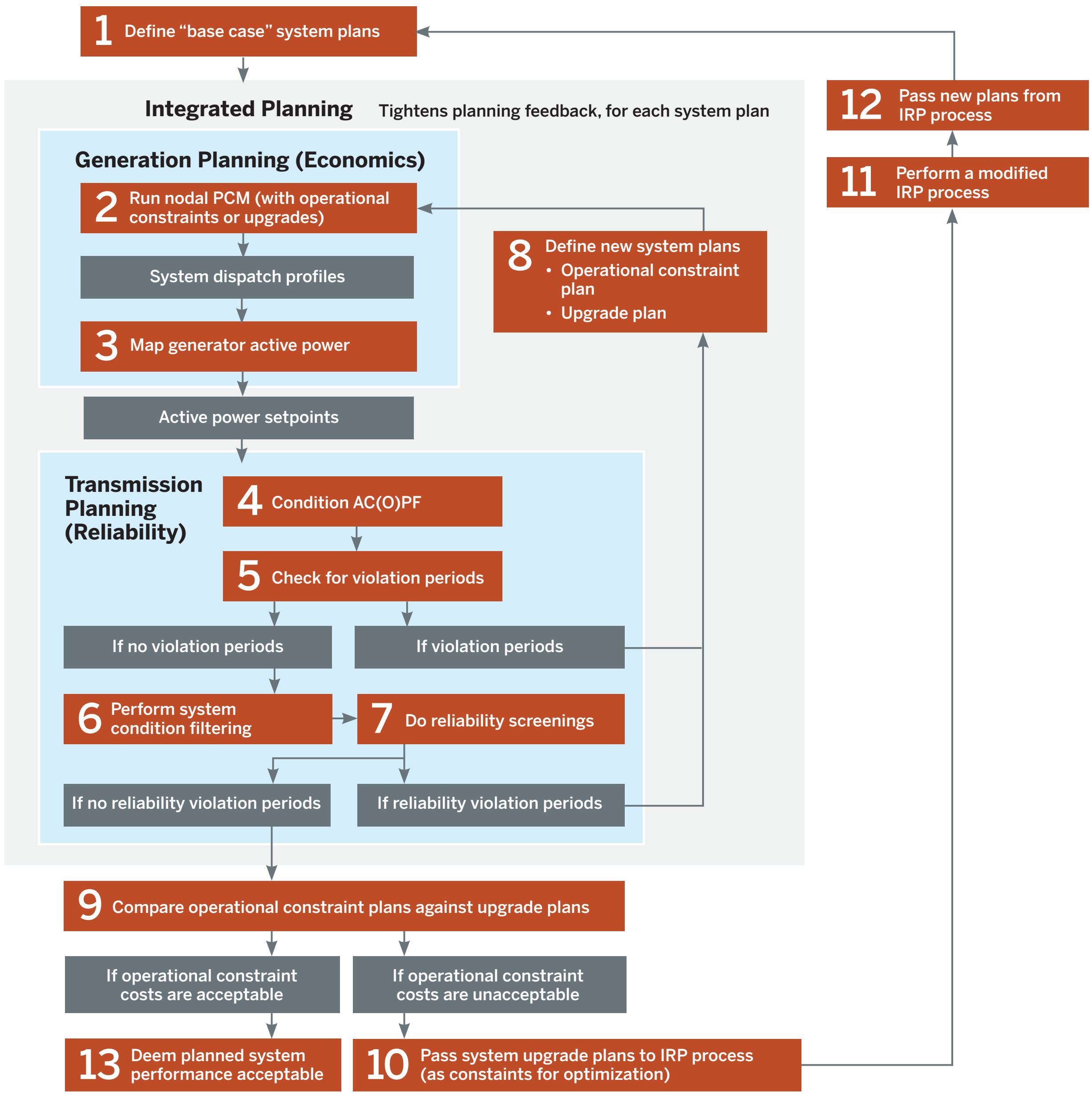
Run

With critical generation and transmission inputs, outputs, and modeling details aligned, planners can begin running integrated planning models. This workflow is intended to uncover how the generation portfolio operates when subjected to reliability constraints of the transmission system in a more comprehensive manner than traditional methods, minimizing unexpected operational constraints with better-informed planning.

Integrated planning in this instance means making sure that system reliability is represented more effectively in generation planning through more robust feedback mechanisms. Figure 2 (p. 30) and the sections that follow

FIGURE 2

Overview of Integrated Generation/Transmission Planning Workflow



This figure shows how generation and transmission planners can integrate their workflows by effectively passing information across modeling domains. Constraints and associated economic ramifications may be acceptable for some plans, while in others, addressing the constraints with system upgrades would be the most cost-effective solution.

Notes: A common time resolution for this workflow is 8,760 hours—hourly data over a year. However, it can also use sub-hourly series, shorter stress periods (days or weeks), or even a single operational snapshot.

The actions taken in steps 4, 5, 6, and 7 are traditional transmission planning methods that are intended to represent an example of an approach. Specifications may vary substantially based on the planner and utility.

IRP = integrated resource plan; PCM = production cost model; AC(O)PF = AC optimal power flow.

Source: Energy Systems Integration Group.

present how generation and transmission planners can integrate their workflows by effectively passing information across modeling domains. Constraints and associated economic ramifications may be acceptable for some plans, while in others, addressing the constraints with system upgrades would be the most cost-effective solution. Having a detailed understanding of the cost of constraints is key to making an expansion decision. The workflow allows a more rapid identification and evaluation of "what if" mitigation schemes to bolster these assessments.

INDUSTRY SPOTLIGHT

Insight from a Planning Expert from a Market Operator

"We are continually manipulating the economic dispatch of our system to meet certain reliability constraints, such as fault current and voltage support. These constraints could be better addressed with more comprehensive planning if the processes were improved."

Importantly, the workflow proposed in this section is intended to complement, not replace, traditional generation planning processes. In the best of cases, the starting point of the workflow is the result of an IRP that already considers many operational constraints. Also critical to the IRP process is the inclusion of asset end-of-life considerations, the results of which are essential for meaningful operational assessments. See the "Integrated Resource Planning" section in "Overview of Generation Planning" for more information on traditional IRP methods.

Following is each step of Figure 2 explained in greater detail.

1. **Define "base case" system plans:** The planning process starts with establishing a "base case" strategy to compare against. A typical base case could be current operations with planned generator installations and retirements that can be the result of an IRP process that considers certain transmission constraints.
2. **Run nodal PCM (with operational constraints or upgrades):** In IRP, the PCM is run to get the active power dispatch time series data of a future scenario and associated costs. The CEM in the IRP process provides a portfolio of generation, transmission, and storage (and demand-side) resources, with some transmission constraints considered in the optimization. Standard ancillary services requirements are included in the initial PCM. Once the workflow has passed through step 5 and/or step 7, the feedback loop constructed by step 8 may generate PCM runs that include operational constraints in the form of security-constrained unit commitment and economic dispatch operations, as well as adjustments to ancillary services requirements to meet reliability constraints.
3. **Map generator active power:** The time series of generator (and storage) active power dispatch from the PCM is mapped to the generator active power set points in the AC(O)PF (AC optimal power flow) simulation.
4. **Condition AC(O)PF:** The ACPF, or ACOPF, time series simulations using PCM outputs are executed. At times this process requires substantial input to adjust device behavior and system topology, especially when the PCM network differs greatly from the ACPF network. The use of ACOPF can minimize manual intervention, as it will optimize the voltage setpoints and more efficiently generate the operating conditions that are the basis for the reliability screenings.
5. **Check for violation periods:** Analyze the ACPF results for periods of time that cause violations (for example, over/under voltages or thermal violations). This process is at times related to the conditioning exercise of the prior step, but in other instances the system is simply not capable of handling the prescribed dispatch without violations. The more accurately the initial PCM model is set up, the less involved this screening process will be.
   a. If ACPF violation periods have been identified, proceed to step 8.
   b. If ACPF violation periods have not been identified, proceed to step 6.
6. **Perform system condition filtering:** Given the intractable computational burden of running reliability screenings of all types, of all contingencies, and for all hours, some type of filtering will be required. The historical result was the selection of the traditional

planning conditions discussed in the section "Traditional Planning Scenarios." A main driver of integrated planning is the need to assess a greater quantity of operating conditions. By establishing this framework, the assessment process is made more efficient, but some filtering will be required to maintain computational tractability.

7. **Screen for reliability:** For each time step selected by the condition filtering, run stability simulations (e.g., steady-state contingency analyses, voltage stability assessments, short-circuit analysis, and small signal stability and large signal stability assessments) based on the needs of the system and computational resources. The computational cost of these reliability studies varies substantially. Whereas a steady-state N-1 assessment of 1,000 elements on a 10,000 node system may take one hour, a dynamic simulation assessing the loss of a single element may take the entire day. While it may be prudent to run steady-state N-1 assessments of all selected hours, the application of dynamic simulations is more targeted.
   a. If stability violation periods have been identified, proceed to step 8.
   b. If stability violation periods have not been identified, proceed to step 9.
8. **Define new system plan:** A system plan may be a combination of operational changes or upgrades to the system. Return to step 2.
   a. **Operational constraints:** New ways of constraining generation (e.g., corridor overloads, inertia constraints, voltage stability issues)
   b. **Upgrades:** Additions to system (e.g., new generation, new transmission, new synchronous condensers or STATCOM devices, new grid-enhancing technologies)
9. **Compare operational constraint plans against upgrade plans:** The benefits and costs of each system plan are now compared. In particular, a direct comparison is made between the cost of constraints and the cost of system upgrades to address the same reliability issue. This process often requires some trade-off analysis to find a system plan that meets planning objectives. Some organizations may use economic evaluation tests discussed in the section "Cost-Effectiveness Tests."
   a. If operational constraints are considered acceptable, proceed to step 13.
   b. If system upgrades are considered necessary, which would be the result of comparing the cost of constraints with the cost of the system upgrades, proceed to step 10.
10. **Pass system upgrade plans to IRP process (as constraints for optimization):** The aggregate set of system upgrade plans that have been proven reliable in steps 2 through 7 are passed back to the IRP process.
11. **Perform a modified IRP process:** Recognizing the enormous effort in a full IRP process, this step aims solely at modifications to capture necessary capacity build-out identified by the operational constraints and subsequent investigation of upgrade plans. This step could involve evaluating system plans by rerunning the CEM to quantify economic trade-offs between different options or by rerunning a probabilistic resource adequacy assessment to quantify the impact on resource adequacy.
12. **Pass new plans from the IRP process:** If a substantial number of upgrades are identified as necessary, steps 2 through 7 can be fully re-executed to ensure that reliability constraints are met with the new system portfolio.
13. **Deem planned system performance acceptable:** If the reliability of the system operation is secured and reflected in the operational dispatch, the planned performance of the system is acceptable.

The system condition filtering of step 6 is critical. It emphasizes the full scope of required analysis with respect to all operating conditions (for instance, 8,760 hours for a future year). Traditional approaches follow this framework for only a few periods—for example, heavy summer and light spring conditions. The more diverse set of operating conditions experienced today suggests that many more operating conditions are susceptible to stability issues, and the framework described here identifies the constraints associated with these periods. While an 8,760 approach is an exhaustive search and certainly not computationally efficient, after a few iterations some basic heuristics uncover the operating conditions to focus on for the specific system under investigation.

INDUSTRY SPOTLIGHT

A Detailed Workflow to Create Time Series ACPF Cases from PCM

Vyakaranam et al. (2021) provides a detailed exploration of innovative procedures to create time series ACPF cases from PCM scenarios. The paper addresses challenges in using PCM data for AC contingency analysis, including a detailed workflow for aligning systems' losses and reactive power inputs in the respective models.

The study emphasizes the importance of converging ACPF for reliability planning studies, using PCM simulation data for unit commitment and dispatch of all generators and location and magnitude of demands. It highlights the ability of the developed procedure to improve voltage profiles by analyzing bus voltage sensitivity to reactive power injections or absorptions. Through a case study using the Western Electricity Coordinating Council's 2028 Anchor Data Set, the paper showcases practical applications for enhancing system reliability and integrating renewable generation.

The authors conclude by underscoring the significance of tools and methodologies for addressing operational challenges in power systems with high shares of renewable energy. The procedures offer valuable insights for power system planners and engineers navigating modern grid complexities.

Integration of Transmission and Distribution Planning

Traditional siloing of transmission and distribution planners has a reasonable physics/mathematical basis in power systems. Transmission networks are the meshed, high-voltage portions of the power system to which most generation elements are directly connected (with the notable exception of DERs). Distribution networks are characterized by typically radial, low-voltage circuits for delivery of power to the customer, each with a single connection point with the transmission system. Redundancy and complex control are core to planning for transmission reliability, where the common approach is a simplification of distribution circuits to single spot load. Distribution planners have traditionally assumed that the availability of energy and voltage profiles are constant on the transmission side of the distribution transformer, which is located at the physical seam between these two levels of the electricity system. Equipment redundancy is typically not a planning objective for distribution systems. These assumptions are a critical element in the integration of transmission and distribution planning processes, where variations in energy supply and voltage regulation capability can have substantial ramifications on the operation of distribution-sited loads and resources.

Walk

What Transmission Planners Need to Understand About Distribution Planning

- Distribution systems are increasingly dynamic due to rising levels of DERs.
- Granular, bottom-up forecasting at the distribution level can differ significantly from system-level (top-down) projections.
- Load behavior is quite variable, with fluctuations driven by customer demand, DERs, and localized grid conditions. This behavior can lead to changes in system operating state (such as high variance in synchronous resource commitment) and changes in contingency response, including decreased demand magnitude for under-frequency load shedding or decreased generation following under-frequency load shedding due to lack of ride-through response for most DERs today.[8]
- Distribution planners may have access to detailed advanced metering infrastructure (AMI) and supervisory control and data acquisition (SCADA) data, but often these data may reside in different planning areas or in other organizations.

What Distribution Planners Need to Understand About Transmission Planning

- Unit commitment, line loading, and device management are key factors in transmission system stability.
- The transmission network operates under broad regional constraints, which may not account for distribution-level variations.

8 IEEE Standard 1548-2018 requires distributed solar inverters to remain connected and generating for some system disturbances to prevent large-scale simultaneous tripping.

INDUSTRY SPOTLIGHT

A Distribution Planner's Thoughts on Historical Distribution Planning Approaches

"Distribution planning has historically been quite subjective, but we now have a much better ability to leverage more granular, external data. This may require new roles at organizations to handle the new sources of data."

- The traditional assumption that the transmission system is an "infinite" resource is becoming increasingly outdated as distribution systems grow more dynamic and complex.
- Understanding transmission constraints helps distribution planners optimize their network without compromising overall grid reliability.
- The response of DERs to bulk power system dynamics can have detrimental impacts. Lack of DER ride-through capability when there are adverse bulk power system operating conditions can result in substantial levels of disconnection. In addition, under-frequency load shedding schemes that target banks of distribution circuits may also inadvertently disconnect similar levels of distributed generation.

Jog

Distribution planners use different software and databases than transmission planners. A key hurdle is mapping distribution transformers between distribution and transmission planning tools, which requires extensive back-and-forth to ensure accurate network position, capacities, and characteristics. If sub-transmission planning is involved, this process becomes even more complex due to the additional networked elements at sub-transmission voltage levels. Following are key inputs and outputs that can be aligned.

Mapping Distribution Feeders to Transmission Demands

A standard methodology can be established for projecting results from the ACPF model to the UACPF model (for example, see the output "bus voltages" in the section "Balanced AC Power Flow" to the "voltage setpoints" in the section "Unbalanced AC Power Flow.")

Aligning Scenarios

Transmission and distribution planners may use different scenarios. While both focus on scenarios that stress their respective systems, transmission planners typically plan against aggregated system peak loads (see examples in the section on traditional planning scenarios in transmission planning), whereas distribution planners focus on scenarios that capture customer-resolution growth (see examples in the section on traditional planning scenarios in distribution planning). It is crucial to align these scenarios, as it directly influences forecasting methods.

Aligning Forecasting Methods

Distribution planners need to communicate the diverse operational characteristics of new system elements to transmission planning teams.

Traditional bottom-up distribution forecasting must be aligned with top-down transmission forecasting. This alignment is complicated by differing objectives: distribution forecasts are increasingly focused on fine-grained, short-term projections—such as DER impacts at the feeder level—while transmission forecasts are typically concerned with long-term, system-wide reliability. These differences can create tensions, as the forecasts are designed to serve distinct planning needs. Coordinated forecasting approaches can explicitly recognize and reconcile these differences to support integrated system planning.

Aligning Timing of Investments

Due to the disparity in investment timing across transmission and distribution, planners from both domains must be acutely aware of the expected deployment of assets, especially those related to mitigating specific constraints.

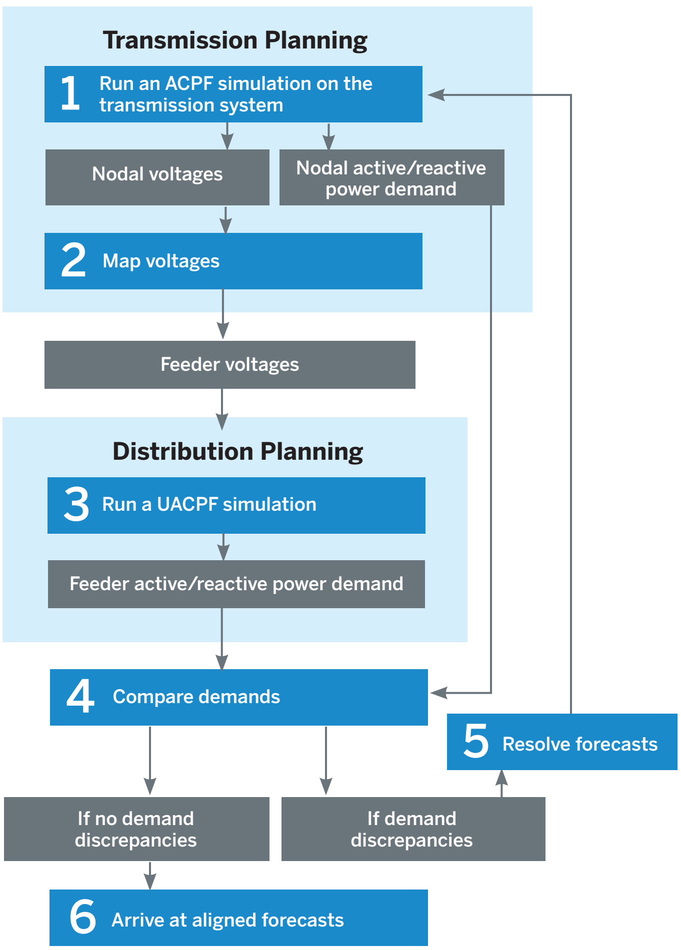
Aligning DER Setting Data

With increasing levels of DERs, the dynamic response of DERs in compliance with the IEEE 1547 standards can have substantial impacts on the dynamic response of the bulk power system.

As distribution planners gain insight into new system elements, they can clearly convey consumption behaviors to transmission planners. This requires aligning bottom-up distribution forecasting with top-down transmission forecasting. Since transmission planners often rely on system-level forecasts and lack granular distribution data, discrepancies in load growth and behavior often arise when comparing the load allocation of these two models.

FIGURE 3

Aligning the Forecast Demands Between Time Series Distribution Power Flow and Transmission Power Flow



This workflow shows a process to align the forecast demands between time series distribution power flow (UACPF) and transmission power flow (ACPF). It uses the general term "time series" to capture the time-varying aspects of the analysis. A common time series is 8,760, an hourly resolution over the course of a year, but a workflow could be performed using other time series such as sub-hourly or a few days or weeks of stress. In addition, a single operational snapshot could be used. Steps 1 through 3 appear also in Figure 4 below (p. 37).

Notes: ACPF = AC power flow; UACPF = unbalanced AC power flow.

Source: Energy Systems Integration Group.

Aligning these forecasts enables more accurate hourly consumption estimates, while understanding demand types and DER magnitudes is crucial for transmission reliability. Figure 3 is an overview of an approach to align these demand forecasts.

Following is each step of Figure 3 explained in greater detail. Steps 1 through 3 appear also in Figure 4 below (p. 37).

1. **Run an ACPF simulation on the transmission system:** Running a time series ACPF simulation on the transmission system will solve the power flow equations to determine the nodal (positive-sequence) voltage magnitude and angles in the transmission system. For further information on ACPF simulation, see the section "Balanced AC Power Flow."

2. **Map voltages:** Map the voltage time series data from the ACPF simulation to the input feeder head voltage for the UACPF simulation. The ACPF simulation result is a single voltage phasor, which is projected under a balanced assumption to generate a balanced set of three-phase voltages at the feeder head for the UACPF simulation. In theory, a balanced load on a distribution system would yield a balanced set of three-phase voltages at the feeder head, and for reasonably balanced distribution systems this projection assumption is reasonable. For distribution feeders that are heavily unbalanced, a combined simulation that models unbalance on the transmission system may be required.

3. **Run a UACPF simulation:** Run a time series UACPF simulation on the distribution system. At this point the distribution system planner can use the simulation results to assess thermal and electrical overloads at the feeder, particularly if the *run* stage is not yet part of the planning objective.

4. **Compare demands:** The active and reactive power of the demands that represent feeders in the ACPF simulation are compared with the feeder active and reactive powers solved for in the UACPF. For this comparison, the per phase active and reactive powers must be aggregated to generate a single-phase equivalent quantity for comparison with the ACPF result. This will obscure any unbalanced loading on the distribution feeder, but is sufficient for general magnitude comparisons.

INDUSTRY SPOTLIGHT

Duke Energy's Approach to Reconciling Different Forecast Methods

"Generation planning continues to use a top-down approach for load forecasting. However, distribution planning is transitioning to a bottom-up circuit forecasting approach to estimate potential overloads. There is a process to reconcile the top-down and bottom-up load forecasts, and a process to better align the information that goes into circuit-level forecasting with transmission-level analyses."

EPRI (2022)

- If there is a substantial difference: Transmission and distribution load forecasts do not agree; proceed to step 5.
- If there is a negligible difference: Transmission and distribution load forecasts generally agree; proceed to step 6.

5. **Resolve forecasts:** The source(s) of the differences between the transmission and distribution load forecasts should be investigated. Possible sources are transmission forecast errors, distribution forecast errors, or underrepresentation of DERs. It should be kept in mind that the power factor settings of demands and the voltage-regulating devices can have a large impact on the resultant reactive power consumption on the feeder. Return to step 1 with the applied change.
6. **Arrive at aligned forecasts:** Transmission and distribution load forecasts are in general agreement.

Run

The *run* stage focuses on iterating between UACPF models of distribution feeders and the ACPF models of the transmission system. By integrating these modeling workflows, planners are better able to understand both operational and system-hardening solutions and solve distribution and transmission performance problems. This analysis can uncover any temporally related delivery constraints that may exist, primarily in the context of the large variability in demand due to changing customer behavior and DERs on the distribution system. This combined modeling will help planners understand the potential reliability aspects of increasing shares of generation sited at the distribution level, especially in the context of contingencies and resultant tripping protective action. Finally, the voltage-regulation capabilities of DERs and the potential propagation of impacts into the transmission system can be deterministically understood, to provide better insight into the siting and preferred performance of these devices.

An iterative approach follows a traditional methodology, incorporating data-handling best practices for time series analysis—whether for specific shoulder hours around system peak or a full 8,760 hours. The process begins with transmission modeling to establish an initial estimate of distribution-level consumption, using system operator or corporate forecasts applied to representative distribution transformer demands. Substation voltage profiles from this step enable time series analysis at the distribution level, capturing hourly or sub-hourly loading based on granular demand and DER representation, informed by AMI-based forecasts. Additionally, the loading assessment on the distribution system can provide valuable insight into the reactive power demand, whether sourcing or sinking, at the feeder head. The resultant power flow refines the transmission model's demand consumption, improving distribution demand accuracy. This iteration continues as needed to converge on a stable loading solution. Figure 4 (p. 37) shows an overview of a process to iterate between UACPF and ACPF.

Following is each step of Figure 4 explained in greater detail. Note that steps 1 through 3 from Figure 3 (p. 35) appear here as well.

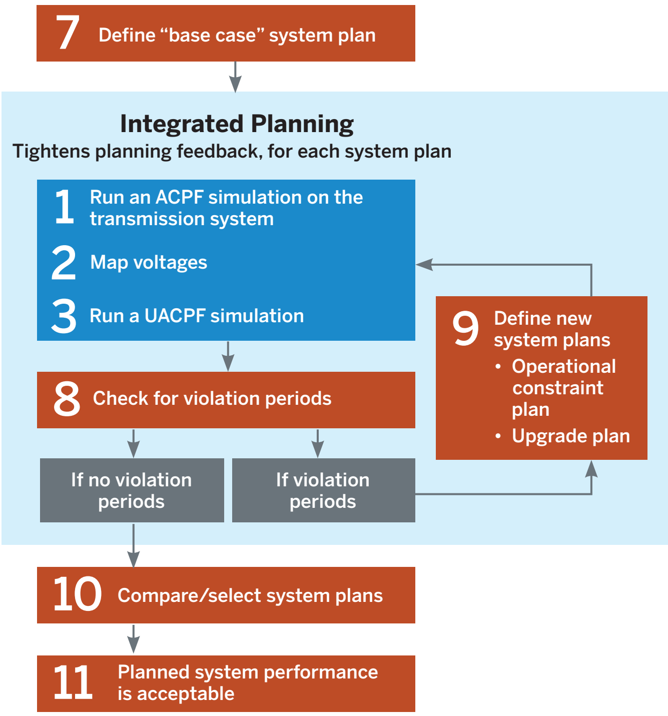
7. **Define "base case" system plans:** Choose a base case to compare against that makes the most sense for the organization. A suitable base case could be current operations and no system upgrades.

1. **Run an ACPF simulation on the transmission system** (see Figure 3).
2. **Map voltages** (see Figure 3).
3. **Run a UACPF simulation** (see Figure 3).

8. **Check for violation periods:** Analyze the operating characteristics of the distribution transformer and feeder, including things like:
   - Currents that go beyond thermal rated values (e.g., unacceptable currents on getaway conductors)

FIGURE 4

Iteration Between Time Series Distribution Power Flow (UACPF) and Transmission Power Flow



This workflow is a continuation of the workflow presented in Figure 3 (p. 35)—once the transmission and distribution forecasts have been aligned, planners can iterate between distribution and transmission power flows to define comprehensive system plans. Note the presence of steps 1 through 3 from Figure 3 here as well. This workflow is primarily aimed at steady-state loading assessments, whether sequences of steady states or representative snapshots. However, the workflow could be used for quasi-static time series approaches to assess the varying voltage-control elements on each system (such as regulator delays). In more complex applications, true dynamic simulations to assess DER responses and interplay with bulk power system dynamics can be executed (Kenyon and Mather, 2020; Hardy et al., 2024).

Source: Energy Systems Integration Group.

- Over/under voltages at customer service points
- Voltage-support devices operating near or at limits
- Phase-balancing issues

  a. If violation periods exist, proceed to step 9.

  b. If no violation periods exist, proceed to step 10.

9. **Define new system plans:** A system plan may be a combination of operational constraints or upgrades to the system. Once the new system plan has been defined, return to step 1.
   - **Operational changes:** For example, if voltages are consistently low on the distribution system, are there resources on the transmission system that could mitigate these issues, such as shunts or generator setpoints?
   - **Upgrades:** These could include things like upgrading the substation capacity, voltage drop mitigation, or non-wires alternatives.

10. **Compare and select system plans:** Compare the benefits and costs of each system plan and select one. This process often requires some trade-off analysis to find a system plan that meets planning objectives. Some organizations may use economic evaluation tests as described in the section "Cost-Effectiveness Tests."

11. **Deem planned system performance acceptable:** The planned performance of the system is acceptable, but planners should regularly check and redo planning exercises as the system changes.

At more advanced stages, or when more granular analysis is needed, it may be practical to simply combine the transmission and distribution networks for direct analysis on the seams of these systems (e.g., when the unbalance of a feeder is high enough to negate the unavoidable balance assumption of positive-sequence ACPF). This can be executed with a variety of co-simulation approaches in which the power flow simulations between transmission and distribution exchange data as the simulations advance through time (Baggu et al., 2024; Hardy et al., 2024). In this context, the "re-run powerflows" block becomes a single multi-model simulation rather than using the iterative walk approach. This can also partially be achieved by populating the zero-sequence data for the transmission network and combining segments with the distribution network so that unbalanced loading conditions can be directly calculated at the transmission level. Given the potential computational tractability issues of including all feeders in a particular territory with the relevant transmission network, this approach is more suitable for targeted analyses.

INDUSTRY SPOTLIGHT

An Example of Integration of Transmission and Distribution at an Island Utility

"As a vertically integrated utility, Hawaiian Electric Company's integrated generation planning process has an emphasis on the coordination and integration of generation, transmission, and distribution planning processes into one comprehensive approach."

SEPA (2020), p. 9

Integration of Distribution Planning and Planning for Customer Loads and Resources

The integration of customer loads and resources planning with distribution planning offers a more comprehensive approach to managing both the demand and supply sides of grid operations, alongside the physical infrastructure of the distribution grid. Customer-based planning focuses on understanding and meeting the needs of specific types of customers, such as through demand response programs, energy efficiency initiatives, and facilitating interconnection of distributed solar. Distribution planning, on the other hand, is concerned with designing, operating, and upgrading distribution infrastructure that delivers electricity to homes and businesses. By integrating these two areas, utilities can create customer programs that target regions where the distribution system needs upgrades, improving the alignment of infrastructure investments with customer needs. This synergy not only enhances the effectiveness of customer programs but can also help strategically design distribution system upgrades to support and amplify the success of these programs, ultimately making the grid more reliable and electricity service more affordable. The operation of DERs on distribution systems is covered explicitly in the section "Integration of Generation and Distribution Planning."

Walk

The factors that drive planning for distribution systems on the one hand, and customer loads and resources on the other, are important for practitioners in these different areas to understand, as are their different backgrounds. For example, distribution planners may specialize in models that represent the physics of local grids, whereas customer planners may specialize in data-driven statistical/heuristic models. Often, both distribution and customer planners are modeling similar underlying processes using different analytical methods, each of which has benefits. Additionally, customer planners may already have greater engagement with generation planners if they are in a vertically integrated setting, as both groups are increasingly focused on reducing or shifting the timing of energy use through energy efficiency and demand-side management programs.

It is important to understand how planners in the other domain consider and conduct modeling in the following areas.

What Planners for Customer Loads and Resources Need to Understand About Distribution Planning

- Primary objectives are assessing the distribution system's physical limitations/constraints and upgrade costs.
- Physical limitations influence the ability of the grid to accommodate increased demand, especially during peak periods or if customer usage changes dramatically.
- Modeling time series datasets is not a typical approach, as peak demand is usually the design criterion.

What Distribution Planners Need to Understand About Planning for Customer Loads and Resources

- Changing customer energy needs complicates forecasting demand.
- Demand response capabilities can vary substantially based on customer adoption of technologies, rate structures, and customers' willingness to participate in programs and events.
- DER adoption trends can vary substantially based on econometrics. These are not easily distinguished feeder by feeder.

Jog

The next stage of integration involves centralizing key datasets. By overlaying customer propensities and demographics with distribution network capacities, planners can make more informed decisions while appreciating and resolving data uncertainties. The *jog* stage involves the following steps.

Aligning Customer Adoption Data

- Planners establish a standardized methodology for projecting the adoption of DERs, including solar, batteries, electric vehicles, heating electrification, and demand response programs down to service transformer granularity.
- Planners ensure that the output of customer adoption models is compatible with inputs for UACPF models.

Unifying Customer Usage Data

- Planning teams align data sources such as SCADA, geographic information systems, and AMI to enhance system monitoring and planning.

By integrating these datasets, distribution planners gain visibility into grid constraints, allowing them to proactively identify areas where customer programs can provide solutions. This also enables targeted, utility-developed non-wires solutions, ensuring that resources are directed toward areas where participation rates are high and impact is maximized.

Run

In the *run* stage, planners execute integrated and iterative modeling analyses using the aligned data to create scenarios that are directly informed by data-driven considerations from distribution planners and planners for customer loads and resources. This workflow is as follows:

1. **Run customer adoption models:** Use models of customer DER adoption to forecast DER growth and load flexibility trends of proposed customer programs.
2. **Map customer resource adoption:** Map projections of customer DER adoption into load demands on a distribution feeder.
3. **Perform UACPF simulations:** Run UACPF models to assess potential grid impacts of the projected customer DER adoption. Identify feeders and substations likely to experience congestion or voltage issues.
4. **Assess grid constraints:** Determine where customer-driven solutions (e.g., demand response, right-time battery charging and discharging) can alleviate distribution constraints. Adjust incentives or program designs to encourage DER adoption in areas with where the distribution can support increased DER deployment.
5. **Adjust customer programs:** Refine the customer program plans based on where DER adoption is most beneficial.
    a. If the customer program is aligned with and addresses distribution constraints, proceed to step 6.
    b. If the customer program is not aligned with distribution constraints, return to step 1 with the adjusted customer program.

- **Deem planned system performance acceptable:** The planned performance of the system is acceptable, but planners should regularly check and redo planning exercises as the system changes.

Where advanced integration is required, such a planning loop may also need to capture real-time system operations. An example of a common real-time system operation that could be considered in integrated customer/distribution planning is an advanced distribution management system that handles real-time power flow adjustments to manage grid constraints and/or DERMS. These systems allow distribution system operators and customer program planners to be more aware of real-time grid conditions. Modeling such systems can often be handled through the use of conditional controllers in advanced power flow modeling software.

INDUSTRY SPOTLIGHT

Salt River Project's Data-Alignment Efforts

"Salt River Project has begun incorporating customers' AMI, measured load data (SCADA), and DER interconnection requests into their distribution planning process to address growing uncertainties around their high rates of growth. The challenges of data alignment between the customers and circuits remain, but these efforts represent a valuable step towards improved growth forecasts. With this customer domain data in the distribution planning process, Salt River Project is able to more accurately address distribution system needs."

SRP (2023)

Integration of Generation and Distribution Planning

It may seem that planning practices that characterize a generation planner are perhaps the furthest from the activities of a distribution planner, given that the primary assets of concern to a generation planner have been generation sources historically located at the transmission level. However, with increasing quantities of DERs, generation planning activities such as CEM, PCM, and resource adequacy analysis are becoming more reliant on tracking DER installation and consistent functioning of these devices at the distribution level. Without this visibility into the magnitude, location, and operation of DERs, generation planning will continue to be executed without realizing the value stack of DERs from across planning areas. The integration of generation and distribution planning is about getting modeling as close as possible to expected operational behavior of these distribution assets, so that sound planning decisions can be made based on actual DER capabilities. These operational behaviors can be understood by applying economic-type dispatch tools to distribution systems with price-responsive devices (i.e., smart thermostats, curtailable solar, controllable storage).

Walk

The first step in integrating the activities of generation and distribution planners is communication. Although a generation planner may most often be considering gigawatt levels of capacity build-out, DERs come online in feeder-by-feeder increments. This is not to say that household details must be built into generation planning models, but for meaningful long-term planning and analysis, planners must at least recognize sources of uncertainty and constraints. As distribution planners start to understand the drivers of flexibility and controllability, they can identify the location and potential capacity of such actors on their circuits.

The first step in integrating the activities of generation and distribution planners is communication.

What Generation Planners Need to Understand About Distribution Planning

- Distribution planning is often done with single snapshots of power flow at peak loading. The system is assessed for thermal and voltage violations.
- Where time series–type applications are not used in distribution planning, operational behavior and potential impacts of DERs are harder to assess. Developing meaningful dispatches outside of peak behavior can be difficult.
- The availability of AMI data is growing; however, the management and quality of these data can vary across organizations, making it a challenge to incorporate into distribution planning processes.
- The location and likely participation of controllable assets is an element of distribution planning.

What Distribution Planners Need to Understand About Generation Planning

- Generation planners use greatly simplified models of the power system in order to execute meaningful short- and long-term assessments.
- Visibility into demand granularity is typically minimal. Feeder-level detail is at best an aggregate of all demand into a single spot load. Often, entire regions or territories are aggregated to a single spot load, depending on the granularity of the generation model.
- In assessing resource adequacy, generation planners need firm capacities. This introduces challenges when constructing plans that may explicitly rely on DERs at certain times. While capacities and optimal dispatch decisions may come from generation planning tools and approaches, customers' behavior is complex, making forecasts of DER behavior challenging.

Questions for the *walk* stage to determine the potential for a meaningful integrated investigation of DER behavior include:

- How might a DER operate daily in response to market conditions?
- Can DERs be effectively controlled in aggregate to achieve power differentials meaningful at the bulk power system level?

- What are the types of energy availability constraints associated with different types of DERs?
- Is congestion a concern for resources on the distribution system?

INDUSTRY SPOTLIGHT

Challenges in Addressing the Different Planning Timelines

"For vertically integrated utilities looking to integrate generation and distribution planning, IRP planning cycles are much longer (10 to 20 years) and conducted at higher levels from the top-down, with a greater focus on generation. Distribution planning processes have shorter time cycles with more granular focus on locations of the system. There may be more cases in the future where DERs contribute to a growing percentage of generation (e.g., Hawaii). Assessment of when this may take place and the future need to integrate these processes will require consideration in these earlier phases."

SEPA (2020), p. 33

INDUSTRY SPOTLIGHT

Oglethorpe Power Corporation's Process for Facilitating Discussions Between Generation and Distribution Planners

"Oglethorpe Power Corporation, one of the largest power supply cooperatives in the United States, is facilitating discussions between distribution planners at its 38 distribution co-ops and its generation planners to start the process of integrated planning. Within Oglethorpe Power Corporation's existing planning process, distribution and generation planners are engaging in regular meetings, collaborative workshops, and information-sharing sessions to align strategies, share insights on capacity planning, and address challenges related to integrating distributed energy resources."

EPRI (2022)

Jog

The understanding established during the *walk* stage builds the foundation for generation and distribution planners to work together on answering key operational questions regarding controllable assets on distribution systems. The key idea of the *jog* and *run* stages of this integrated workflow is extending generation optimization techniques to distribution systems to configure the behavior of DERs that may be price-responsive. In this case, price is a proxy for a behavioral signal, which can be used to generate a variety of DER responses based on network operating conditions (i.e., demand response due to contingency-caused congestion). This process will allow distribution planners to generate expected loading profiles on their network, while providing information for bulk power system planners about expected behavior of DERs. The following are key steps to aligning the data and assumptions for this workflow.

Aligning Behavior Through Economic Data

- Generate price proxy data indicative of a system behavior (hourly-level data) for distribution feeder source points that originate from generation planning studies. This enables the application of economic modeling practices to a distribution system. These would most likely be in a price-taking (non-competitive) structure.
- Determine congestion pricing on the distribution system to generate price signals for DERs when violations occur

Aligning Time Series Data

- Disaggregate demands to distinguish between solar photovoltaic behavior and true loads; for example, shift modeling of distributed solar from "load modifiers" to a disaggregated modeled resource that follows a solar shape

Characterizing DER Response for Generation Planning Optimization

- Share the potential price-responsive behavior—and management limitations—of DER devices with generation planners optimizing the device response
- Incorporate the temporal variability demand response capabilities into DER data (i.e., must the demand be served later if reduced? Or is the demand purely elastic?)
- Represent the energy capacity and charging constraints of storage

Mapping Each DER to Its Location Distribution System

- Understand a DER's exact position on the feeder, as this is critical for accurate distribution system modeling and validating dispatch scenarios developed through generation planning tools

By integrating these distribution and generation datasets, planners create a framework to gain real-time visibility into grid constraints, which will allow them to proactively identify areas where controllable DER assets can have a meaningful impact on the system.

Run

The *run* stage of integration investigates the operational characteristics of DERs for energy impacts on the bulk power system and loading impacts on the distribution system. This stage requires determining a credible behavior of DER devices to construct meaningful loading patterns on the distribution system, which will require some sort of optimization tool. In the workflow presented in this section, the tool of choice is a PCM that can be applied at the distribution system level with similar network relaxations (i.e., the distribution network is represented with positive-sequence reactances and a multiplying factor for single-, and double-, phase sections to capture the loadability limits).[9] Therefore, the LMP is the signal to which DERs are expected to respond. The LMP referenced in the workflow will be whatever control signal is desired for that implementation. While applying a PCM to an unbalanced distribution system does incur some error, a tight feedback loop with a UACPF tool in the workflow allows for a rapid assessment of this error and the application of necessary mitigations.

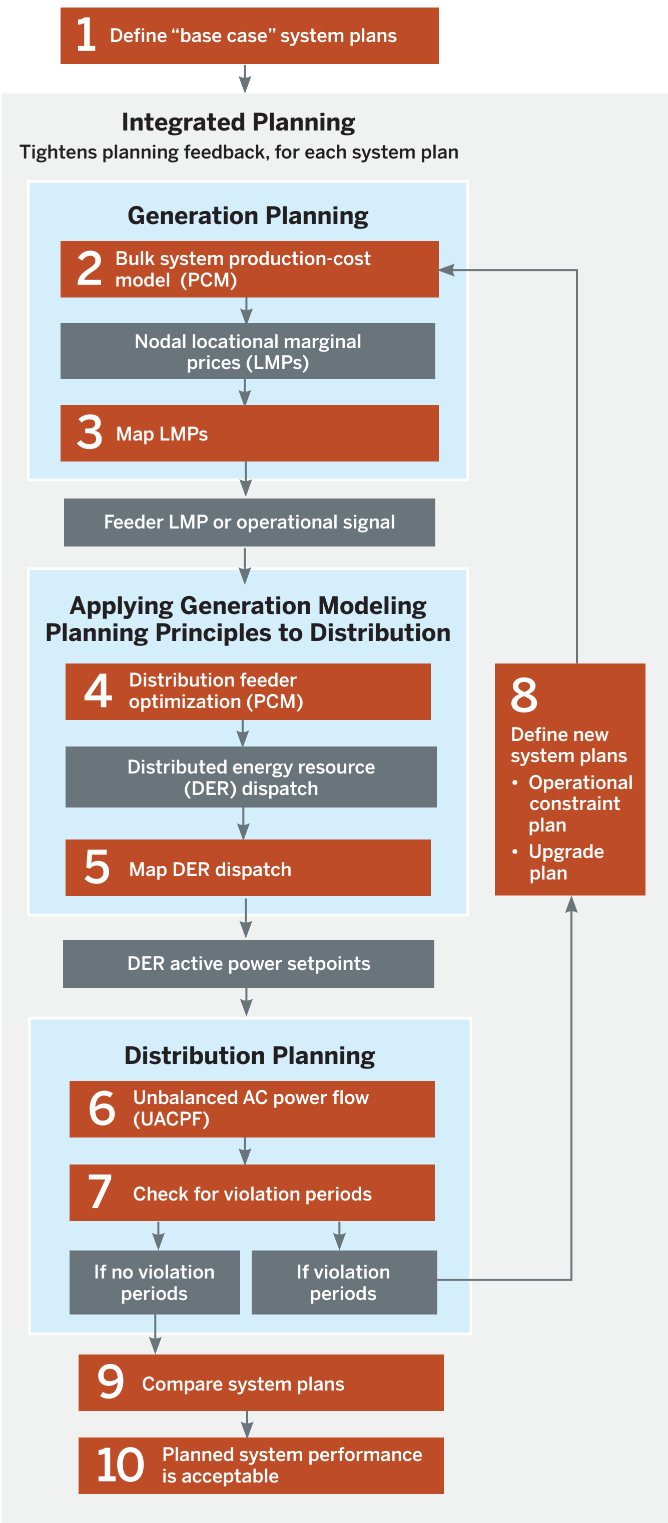
This workflow iterates between a PCM of the bulk power system, a PCM applied to distribution feeders, and a UACPF model applied to the distribution feeders. The response of DER devices to contingencies can also be assessed by applying penalty prices to certain loading conditions—i.e., a contingency that causes a transmission line to be overloaded would produce an LMP characterized by the penalty price attached to the overloaded line, and local DERs could be tuned to respond to this price increase. This workflow, depicted in Figure 5 (p. 43), follows optimization of capacity expansion, either through a CEM, as covered in the section "Capacity Expansion Modeling," or an IRP process, as covered in the section "Integrated Resource Planning."

1. **Define "base case" system plan:** Choose a base case that makes the most sense for the organization. For example, a suitable base case could be current operations and no system upgrades.
2. **Run bulk system PCM:** Use a price-forming model to develop DER response signals to congestion/line loading in the form of LMPs. See the section "Production Cost Modeling" for further details on LMPs. The model does not need to be perfectly tuned, as its purpose is primarily to develop a control signal for assessing the response of DERs on distribution systems. This relaxation in precision means the approach is meaningful for those entities without market structures, that may not have well-tuned price models.
3. **Map/construct LMPs (or other control signals):** Using the mapping established in the *jog* stage, map the LMPs from the bulk power system nodes to their corresponding distribution feeder. A precise LMP is not required, as the express goal is to generate a price signal to which DERs will respond to produce a practical loading pattern. The LMP could be generated based on generic loading/clearing costs for utilities in regions without centrally organized markets.
4. **Optimize distribution feeders (PCM):** Use a price-taking model to dispatch DERs on the distribution feeder according to the set LMP at the feeder. Constraints on the distribution system can be captured with penalties, which will establish different LMPs on the distribution system that can be used to generate varied DER responses (e.g., solar curtailment or storage charging/discharging as the result of an overloaded distribution transformer).
5. **Map DER dispatch:** Using the mapping established in the *jog* stage, transfer the solved DER dispatch from the PCM (or chosen optimization method) to the corresponding setpoints in the UACPF model for time series analysis.
6. **Run UACPF simulation:** Run the UACPF simulation on distribution feeders using the active power setpoints generated in step 4. Because the PCM application is necessarily a simplification of the distribution network, some differences in loading are expected once the individual phase granularity is re-introduced. However, a tight feedback loop between the PCM and UACPF

9 Planners may opt for more comprehensive multi-phase ACOPF tools, but this substantially increases in computational cost.

FIGURE 5

Iteration Between Production Cost Model and Unbalanced AC Power Flow



allows simple modifications in the optimization constraints to address unintended phase violations (e.g., a single-phase violation, when the average adheres to the PCM captured loading constraints).

7. **Check for violation periods:** When analyzing the performance of the distribution system, common areas to look at include:
   - Currents that go beyond thermal rated values (e.g., unacceptable currents on getaway conductors)
   - Over/under voltages at customer service points
   - Voltage-support devices operating near/at limits
   - Phase-balancing issues

   While traditional peak demand planning captures these elements, this workflow creates a framework that allows a straightforward time series–type analysis of distribution system loading. This is particularly important for assessing the duration of loading violations and charging/discharging behavior of distributed storage devices.

   a. If no violation periods exist, proceed to step 9.

   b. If violation periods exist, proceed to step 8.

8. **Define new system plans:** A system plan may be a combination of operational changes or upgrades to the system. Once the new system plan has been defined, return to step 2.

   a. **Operational constraints:** Implement operational policies (e.g., penalty prices on lines, demand response prices) that prevent overloading by changing the operation of DERs on the distribution system.

This workflow iterates between a PCM of the bulk power system, a PCM applied to distribution feeders, and a UACPF model applied to the distribution feeders. The response of DER devices to contingencies can also be assessed by applying penalty prices to certain loading conditions—i.e., a contingency that causes a transmission line to be overloaded would produce an LMP characterized by the penalty price attached to the overloaded line, and local DERs could be tuned to respond to this price increase.

Notes: DER = distributed energy resource; LMP = locational marginal price; PCM = production-cost model; UACPF = unbalanced AC power flow.

Source: Energy Systems Integration Group.

b. **Upgrades:** Implement upgrades, which could include upgrading the substation capacity, voltage drop mitigation devices, or non-wires alternatives.

9. **Compare system plans:** Compare the benefits and costs of each system plan. This process often requires some trade-off analysis to find a system plan that meets planning objectives. Some organizations may use economic evaluation tests described in the section, "Cost-Effectiveness Tests."

10. **Deem planned system performance acceptable:** If reliability criteria are met through system upgrades and operational adjustments, the planned performance of the system is acceptable. Planners should regularly check and redo planning exercises as the system changes.

INDUSTRY SPOTLIGHT

An Example of Aggregate Representation of Distribution Resources from the ESIG Report on Vehicle Electrification

"The study assumed that distribution systems are sufficiently robust to integrate the levels of distributed generation resources simulated and that transmission-distribution interfaces are sufficient to allow excess distributed generation to flow onto the bulk transmission system (as needed). As such, distributed generation resources were represented as generators in the model's zones alongside utility-scale resources, serving as a key part of the hour-to-hour energy balance maintained in study simulations. However, in this study, distributed generation and storage had unique assumptions to reflect their unique nature as generation resources."

ESIG (2023), p. 6

Distribution planners can screen for feasible operation of DERs and act as a liaison between generation planners and customer load and resource planners. Aligning time series data for expected behavior of controllable assets for analysis of, and market rules or constraints for, DER participation will help distribution planners inform other planning areas. If DERs are to be used optimally in conjunction with the rest of the resources in the power system, they will need to respond to market signals beyond that of any individual distribution feeder. If this analysis suggests that DER operations will influence the market, planners may need to iterate the distribution PCM with the bulk system PCM from step 1. In other cases, interactions can be co-simulated similar to what was discussed in the section "Integration of Transmission and Distribution Planning." This would involve exchanging control signals between the bulk power system PCM and distribution simulation at every time step (Hansen et al., 2019; Hardy et al., 2024). Both methods are intended to capture stimulus-response interactions between power flows and consumption patterns.

Integration of Generation Planning and Planning for Customer Loads and Resources

The integration of generation planning and planning for customer loads and resources is critical for enabling effective long-term planning that accounts for both supply and demand dynamics. Generation planning involves determining how to meet future energy demand through development and management of assets that produce power, including conventional thermal plants and renewable resources. Planning for customer loads and resources focuses on aligning utility programs for energy efficiency, demand response, and other DERs with customers' preferences and needs. By integrating these planning sectors, generation decisions can be shaped by strategies for customer programs and rate structures (Carvallo and Schwartz, 2023), and customer programs can be informed by generation plans.

Walk

The effective integration of generation and customer loads and resources planning starts with mutual understanding of each area's objectives, constraints, and methodologies. Even in organizations with frequent collaboration between these planners, there may be new planning dynamics and assumptions to explore and strengthen. By aligning insights, both teams can better forecast demand, optimize DER adoption, enhance grid reliability, and minimize electricity costs.

What Planners for Customer Loads and Resources Need to Understand About Generation Planning

- Generation planners ensure long-term resource adequacy, reliability, and economic dispatch—understanding these priorities helps customer planners align customer solutions with system-wide needs.
- High solar adoption without storage creates evening peak challenges, requiring careful load-shifting strategies to increase system flexibility.
- Programs that increase demand, such as encouraging electric vehicle adoption and heating electrification, may trigger the need for additional generation resources (new capacity investments), while demand response and storage can defer the need for these investments.

What Generation Planners Need to Understand About Planning Customer Loads and Resources

- Customer behavior is dynamic, driven by customer needs, incentives, rate design, market trends, and other factors.
  - The impacts of DERs vary. Solar alone shifts mid-day load, potentially reducing peak demand, but can lead to significant ramping before evening peaks. Adding storage changes solar customer load profiles, and demand response also reshapes them.
- Not all customer programs directly align with generation needs. Targeted incentives for DERs at specific locations and times improve grid value.
- DER adoption is not uniform across the utility system. Localized spatial impacts must be incorporated into bulk planning.

Jog

In the *jog* stage, planning teams focus on aligning data that enable mapping DER adoption to customer load patterns, improving forecasting, and improving integration in generation planning models. This requires collaboration between generation planners and customer planners to establish a shared framework for how DER adoption influences individual load behaviors. Following are key areas of alignment.

INDUSTRY SPOTLIGHT

A Consultant Perspective on DER Adoption

"Be sure to take incentives and other programs that might substantively alter adoption into account. [It] seems obvious, but it also appears to be a common mistake!"

Aligning Customer Load Profiles

- Establish common baseline customer load patterns, segmented by customer type (residential, commercial, industrial)
- Identify and align typical daily and seasonal variations in energy usage
- Ensure that load profiles from load forecasting models (see "Load Forecasting Models") are in a format usable with the demand forecast input defined for PCMs and CEMs (see "Production Cost Modeling" and "Capacity Expansion Modeling")

Mapping DER Adoption to Load Profiles

- Define the impacts of different types of DERs (solar, batteries, electric vehicles, demand response) on individual customer load curves
- Capture behind-the-meter generation and storage behaviors and adjust net load profiles accordingly
- Provide DER adoption trends from customer adoption models (see "Customer Behavior and Adoption Models") in a format usable with the demand forecast input defined for PCMs and CEMs (see "Production Cost Modeling" and "Capacity Expansion Modeling")

Defining DER Reliance Criteria

- Put in place a controllability mechanism, such as a DERMS, for distributed generation (aggregations of DER devices) that may be critical for system reliability
- Establish other criteria for reliance on DERs before developing meaningful plans

By integrating these datasets, teams map DER adoption to load behavior at a customer level, allowing generation planners to incorporate more precise demand profiles into CEMs and PCMs.

Run

The *run* stage focuses on iterating between adoption models for customer resources and generation planning models (CEM/PCM) to align DER adoption with grid needs. By integrating customer-driven insights and generation capacity forecasts, this stage ensures that both customer programs (and rate structures) and generation resources are optimized to meet future energy demands. It is also an opportunity to investigate controllability mechanisms (i.e., SCADA/DERMS) that utilities will likely require in exchange for reliance on DERs for operational purposes. This iterative process continually refines customer adoption strategies and grid planning, fostering better coordination between customer-driven initiatives and generation capabilities. The proposed workflow is as follows.

1. **Run customer adoption models:** Use customer adoption models (e.g., customer segmentation data, propensity models) to forecast the adoption rates and behaviors for various DERs (e.g., solar, batteries, electric vehicles, demand response).
2. **Map adoption:** Take outputs from the customer adoption model (e.g., projected DER penetration rates, demand shifts) and use the mapping developed in the *jog* stage to input the resulting load profiles into the PCM models to simulate the grid's operations.
3. **Assess operations:** Use PCM models to assess the impact of customer resource adoption on overall system operations, including changes in generation adequacy, resource mix, and costs. This may also involve updating estimated retail rates to capture their interaction with customer resource adoption.
4. **Assess operational constraints:** Determine where customer-driven solutions (e.g., demand response, battery incentives) can help grid operations. Adjust program designs, including incentive levels, to encourage DER adoption in areas with excess local grid capacity.
5. **Adjust customer program:** Refine customer program plans based on behavior modeled in the PCM.
   a. If the customer program is aligned with optimal operations, proceed to step 6.
   b. If the customer program is not aligned with optimal operations, return to step 1 with the adjusted customer program.
6. **Deem planned system performance acceptable:** The planned performance of the system is acceptable. Planners should regularly check and redo planning exercises as system changes.

The addition of significant distributed generation and storage, demand response, energy efficiency, and electrified end uses sourced through customer programs may have a meaningful impact on generation planning. Closing this loop is important to make sure that the most likely DER scenarios are captured in generation models.

The Value of Integrated Planning

While integrated planning has more complexity than traditional planning approaches, it has tremendous value for harnessing the interconnected nature of modern power systems and maintaining reliable electricity service at least cost. By adopting a comprehensive and iterative framework, integrated planning delivers significant benefits across multiple dimensions, as Figure 6 shows.

Although integrated planning requires greater effort and coordination, its ability to better plan power systems that are reliable and affordable makes it critical to navigating the complexities of the modern energy landscape.

The Value of Integrating Generation and Transmission Planning

In today's energy landscape, integrating generation and transmission planning is essential to optimize infrastructure investment and ensure grid reliability. For example, strategically locating generation assets near load centers can mitigate expensive transmission upgrades. And assessing and planning for the impacts of increased levels of IBRs is important for effectively balancing supply and demand, maintaining grid stability and reliability.

FIGURE 6

Benefits Delivered by Integrated Planning Across Multiple Dimensions

Lower costs	Integrated planning optimizes resource allocation, eliminating redundancies and reducing overall expenditures.
Increased system resilience	Planning with a comprehensive view of the energy system strengthens the system's ability to withstand disruptions, thus increasing safety, reliability, and adaptability in the face of changing demands.
Streamlined processes	Integrated planning promotes smoother utility operations by enabling coordination and consistent data sharing across planning areas.
Data integrity	Integrated planning standardizes assumptions and shared datasets for planning across generation, transmission, distribution, and customer loads and resources, thus reducing errors and improving process efficiency and electricity system reliability.
Accurate benefit accounting	Integrated planning avoids double-counting benefits while ensuring that the unique advantages of each planning area are effectively incorporated into system-wide strategies. Integration also enables a clearer assessment of reasonable reliance on markets and power purchases, ensuring that system benefits are considered not only internally but also in the context of broader market interactions and regional coordination.
Ability to balance competing objectives	Integrated planning enables trade-off analysis among priorities, such as maintaining grid reliability, ensuring grid resilience, and minimizing costs. By providing a comprehensive view of system needs and objectives, integration also facilitates more meaningful stakeholder engagement.

Source: Energy Systems Integration Group.

INDUSTRY SPOTLIGHT

The Value of Cross-Planning-Area Understanding

An EPRI report on integrated planning discusses how electric companies are increasingly acknowledging the significance of collaborative endeavors across various sectors (EPRI, 2022). The report sheds light on the pivotal role of integrated planning in meeting long-term objectives in a reliable and cost-effective manner.

All of the companies interviewed for the report "recognized that there is value in closer collaboration across generation, transmission, and distribution and consumer-sided resources, and in understanding how to optimize a more coordinated system to reduce costs" (p. 49).

This statement succinctly captures the collective acknowledgment within the industry of the importance of fostering enhanced collaboration and streamlining system coordination to drive efficiency and cost-saving initiatives. The report underscores the diverse array of integrated planning strategies and needs among various industry players. This diversity in approaches highlights the adaptability and versatility of integrated planning methodologies in addressing the distinct requirements of different organizations in the energy sector.

Benefits of integrating generation and transmission planning include the following.

- **Avoiding costly transmission upgrades with optimized generation placement:** Strategically locating generation assets can mitigate the need for expensive transmission infrastructure investments.

  Example of avoiding transmission bottlenecks
  A regional utility facing transmission bottlenecks adopts a strategic generation siting approach by:

  – Encouraging the development of distributed generation and storage at or near customer loads to reduce transmission strain

  – Assessing the trade-offs of siting wind and solar facilities closer to load centers that minimizes the need for extensive transmission upgrades, even if resource capacity values are lower than more distant renewable resources

  – Aligning generation expansion with existing transmission capacity to optimize resource delivery

INDUSTRY SPOTLIGHT

TVA on How Integrating Generation and Transmission Planning Decreases Overall Costs

"Historically, TVA has had a resource planning unit and a transmission planning unit, with teams working together as necessary. However, over the last one to two years, company units have become more tightly integrated because of the larger changes it sees over the horizon. The company recognizes that there is value in transmission planning and generation planning units partnering more closely to co-optimize generation and transmission investments to decrease overall costs."

EPRI (2022), p. 32

- **Assessing the impact of IBR integration on transmission capacity:** Connecting large numbers of IBRs in a given area requires careful assessment of transmission capabilities to avoid grid disruptions.

  Example of wind farm integration
  A utility with a potential significant increase in wind energy capacity responds by:

  – Performing detailed grid simulations to understand the impact of variable wind generation on transmission lines

  – Planning for dynamic line rating technologies to optimize existing transmission infrastructure and accommodate fluctuations in renewable energy output

  – Coordinating with transmission operators to enhance grid flexibility

  Example of avoiding uneconomical transmission build-out driven by renewable curtailment
  A utility conducts a trade-off analysis of the cost of curtailing variable renewable energy production and the cost of grid upgrades by:

  – Running operational and reliability simulations to quantify the cost of curtailment driven by transmission constraints

  – Calculating the cost of transmission system upgrades necessary to avoid curtailment

- **Improving system reliability through coordinated generation and transmission planning:** Planners can ensure that generation capacity aligns with transmission capabilities and enhances system reliability and that coordinated planning minimizes costs.

  Example of co-located solar and battery projects
  A utility co-locates solar generation with batteries:

  – Storing solar energy that can be dispatched during peak demand hours to relieve transmission congestion

  – Enabling the integration of additional variable energy resources, avoiding transmission overloads, and planning for energy availability during critical periods

- **Maximizing power density on transmission rights-of-way:** Planners optimize the use of existing transmission corridors by deploying advanced conductors and other advanced grid technologies and designing strategies to increase power transfer capacity on existing rights of way.

  Example of transmission corridor co-optimization
  A vertically integrated utility ensures that transmission corridors deploy best-available technologies by:

  – Improving the application of flexible AC transmission systems (FACTs) devices to increase transmission capacity factors

  – Optimizing the operation of IBRs for voltage support and minimized system losses

- **Developing transmission projects that drive investments in lower-cost generation:** Planners propose investing in a transmission project that encourages generation investments and leads to lower total system cost.

  Example of transmission projects driving major generation investments
  Competitive Renewable Energy Zones (CREZ) were areas in Texas targeted for transmission development to support the cost-effective integration of renewable generation. Transmission upgrades were built proactively in these areas by:

  – Encouraging competition and developing high-quality generation projects at least cost

  – Keeping transmission lines loaded to levels that reduce losses

INDUSTRY SPOTLIGHT

Texas's Competitive Renewable Energy Zones

An article about a major transmission project in Texas that has driven major generation investments and interconnections, "CREZ Is Generally Recognized to Be a Tremendous Infrastructure Success Story."

Power Up Texas (2018)

The Value of Integrating Transmission and Distribution Planning

The distribution transformer, as the physical seam between transmission and distribution networks, has historically been a valid point of separation between these two networks and between planning areas. However, with increased diversity in demand, including new end-use equipment and customer behavior, the exchange of power across this seam is becoming more complex. There is significant value in tightening up the exchange of information between these planning processes. That includes a more granular understanding of the potential

The distribution transformer has historically been a valid point of separation between the transmission and distribution networks and between planning areas. However, with increased diversity in demand, the exchange of power across this seam is becoming more complex.

INDUSTRY SPOTLIGHT

Recognizing the Value of Integrated Planning Across Transmission and Distribution

"As DER adoption increases challenges along the grid, the lack of integration between transmission and distribution may lead to extra work for interconnection processes. A utility processing a distribution interconnection request may discover that the requested project may not pass the transmission interconnection test. These additional steps have slowed the approval process in some cases."

SEPA (2020), p. 33

loading and criticality of the distribution transformer, particularly in the context of capacity planning, considering its high replacement costs and long manufacturing lead times.

Example of accurately predicting transformer lifespans
A utility employs integrated modeling to better predict transformer needs, potentially delaying costly replacements (while accounting for long lead times in manufacturing and replacement) by:

- Analyzing granular demand data to assess the potential impact of equipment and customer behavior on transformers
- Implementing predictive maintenance programs that prioritize transformers based on loading forecasts and criticality assessments
- Optimizing transformer capacity

Other benefits of integrating transmission and distribution planning include:

- **Avoiding redundant upgrades:** Aligning transmission and distribution needs helps prevent unnecessary, duplicated upgrades.

  Example of joint planning studies
  A utility conducts a joint planning study to prioritize investments by:

  - Identifying and prioritizing investments that benefit both systems
  - Using shared infrastructure improvements where possible to minimize capital expenditures (e.g., a transmission system upgrade that improves distribution voltages may make it unnecessary to install a voltage regulator)
  - Providing flexibility in potential land use for future load growth by customers connected at the distribution or transmission level

The Value of Integrating Distribution Planning and Planning for Customer Loads and Resources

Integrating these planning areas allows utilities to optimize grid investments, enhance reliability, and improve program outcomes by aligning customer-driven DER adoption with distribution system needs. Benefits of integration include the following:

- **Avoiding costly distribution upgrades with targeted DER investments:** Utilities can use programs, procurements, or pricing to target customer adoption of DERs where it is needed and cost-effective to manage grid constraints.

  Example of using non-wires alternatives
  A utility facing distribution and sub-transmission congestion may defer a costly substation upgrade by:

  - Offering incentives for energy efficiency, battery storage, and demand response in constrained areas
  - Deploying virtual power plants to reduce peak loads
  - Aligning customer adoption of DERs with grid relief needs, maintaining reliability at lower cost

- **Assessing the engineering and operational impacts of customer programs:** Some types of customer programs can create grid challenges if not coordinated with distribution planning.

  Example involving the growth of electric vehicle adoption
  A projected electric vehicle adoption rate could lead to feeder overloads. This can be avoided by:

  - Modeling charging impacts under representative scenarios
  - Deploying managed charging programs to shift demand off-peak and prevent system stress
  - Adjusting incentives to steer electric vehicle charging stations to where grid capacity is available

- **Improving program success through customer-grid alignment:** Customer programs are effective if they are both attractive to customers and beneficial to the grid.

  Example of creating solar and storage incentives that align with grid needs
  A utility considering how to plan its solar plus storage customer program decides to target incentives to boost adoption where peak demand relief is needed, reducing costs of distribution system upgrades.

  - Without integration, solar adoption is high in areas with excess capacity, but low where grid constraints exist, and little solar plus storage adoption occurs.

- With integration, targeted incentives boost the adoption of solar plus storage where peak demand relief is needed, reducing distribution upgrade costs.

By integrating customer and distribution planning, utilities can proactively shape customer adoption to maximize distribution system benefits—resulting in lower upgrade costs, improved reliability, and more effective customer programs.

The Value of Integrating Generation and Distribution Planning

Integrating generation and distribution planning offers long-term benefits by coordinating the availability of distribution-sited resources, the infrastructure needed to enable them, and their role in the bulk power system. With the increasing deployment of a diversity of DERs, an integrated approach and analysis will be necessary to design electricity systems that can rely on distribution-sited assets as well as transmission-level generation assets.

INDUSTRY SPOTLIGHT

Potential Impacts of Distribution-Sited Controllable Load on the Bulk Power System

"Smart [electric vehicle] charging that is driven by bulk power system needs could undermine load diversity on the distribution system by concentrating charging during specific time periods that address bulk system needs but exacerbate stress on the distribution system."

ESIG (2023), p. 40

Benefits of integrating generation and distribution planning include the following.

- **Localized energy balance that reduces losses:** Balancing energy supply and demand closer to the point of use minimizes transmission losses and enhances overall grid efficiency.

  Example of rooftop solar integration
  A utility reduces transmission losses by promoting rooftop solar installations in residential areas with available hosting capacity, and also incents battery storage to manage potential distribution system overloads.

- **Enhanced grid reliability and resilience:** Integrating decentralized energy systems like microgrids strengthens the grid's ability to withstand and recover from disruptions, improving reliability and resilience. Additionally, the ability of DERs to provide bulk system ancillary services can be assessed.

  Example of microgrid deployments
  A utility enhances resilience by establishing microgrids in critical regions by:

  - Installing local resources, such as solar and battery storage, to provide power during grid outages
  - Allowing distribution microgrids to operate independently (island mode) from the main grid, if needed, ensuring continuous power supply to essential services during disruptions

The Value of Integrating Generation Planning and Planning for Customer Loads and Resources

Integrating customer and generation planning allows utilities to optimize resource investments, enhance grid flexibility, and reduce system losses by aligning customer-driven DER adoption with evolving generation needs. Benefits of integrating customer and generation planning include the following.

- **Avoiding costly generation investments with targeted DER deployment:** Utilities can use DERs to balance supply and demand more effectively, rather than investing in new large-scale generation assets.

  Example of virtual power plants and demand response
  A utility facing a need for additional generation in order to serve load reliably can defer investments in new power plants by:

  - Leveraging virtual power plants to aggregate customer-sited resources such as energy efficiency and solar plus storage systems
  - Offering demand response incentives to reduce load during peak periods
  - Optimizing customer DER adoption to complement existing and planned generation capacity, for example, incentivizing the installation of smart thermostats and controllable water heaters to shift energy use to off-peak hours and reduce peak demand

- **Enhancing grid flexibility and reliability with DERs:** With increased levels of variable energy sources, utilities need flexible solutions to maintain reliability.

  Example of managing renewable integration
  High levels of solar and wind can create overgeneration and curtailment challenges. Integrated planning enables utilities to:

  – Align customer incentives for energy storage with periods of surplus renewable generation

  – Encourage smart electric vehicle charging to absorb excess wind or solar generation that would otherwise be curtailed

  – Use flexible load programs to modulate demand so that it better aligns with the output of variable generation resources

Key Concepts for Integrated Planning Software

Integrated planning is a multi-staged process that unlocks critical value for modern planners. The remainder of this guidebook focuses on *implementing* integrated planning. This chapter examines software concepts that facilitate integrated planning workflows, and the next chapter explores organizational opportunities for adopting integrated planning.

The Current State of Planning Software

Today's planning technology has evolved alongside traditional planning processes. Most planning for generation, transmission, distribution, and customer loads and resources is conducted using software, typically designed to model system performance within specific planning areas (see "Overview of Electric Power System Planning: Structured Across Consistent Dimensions"). These tools share several characteristics, which are outlined here to contrast with the emerging technologies discussed later. While these attributes have historically served the industry well, they also present limitations when applied to integrated planning efforts.

Built for a Single Planning Area

Most existing energy planning software is designed for a single planning area. As discussed in "Overview of Electric Power System Planning: Structured Across Consistent Dimensions," the planning industry has traditionally been structured in silos, and the associated

purpose-built tools reflect this separation. For example, transmission planning software typically incorporates modeling domains such as ACPF, phasor-domain, and EMT (see "Modeling Domains" in the transmission planning discussion) and supports analytical methods like contingency analysis, voltage stability assessments, and short-circuit analysis (see "Analytical Approaches" in the transmission planning discussion). However, these tools do not generally include capabilities relevant to other planning areas, such as PCM, CEM, or customer resource adoption modeling. In the past there was not a need for such cross-domain capabilities.

Legacy Technology

Many widely used planning software solutions are built on legacy software stacks. The complexity of planning mathematics, the scarcity of alternative software, and the critical nature of planning assessments have fostered strong institutional trust in the incumbent tools. This preference for familiar solutions often hinders technological innovation, as vendors prioritize maintaining a consistent user experience for their established user base.

Additionally, regulators, stakeholders, and community groups reviewing energy plans are often accustomed to these legacy tools and the assumptions embedded within them. Shifting to newer technologies is not just a technical challenge but also a stakeholder engagement challenge, as changing methodologies can introduce uncertainty or require additional education and trust-building. As a result, outdated assumptions, such as non-varying, non-dispatchable, and highly predictable demand, persist in both planning software and the planning processes themselves.

Integrated Concepts

New software is emerging to support integrated planning. The following sections highlight key considerations for evaluating integrated planning software. To the best of our knowledge, at this point in time no single software solution fully embodies all these aspects.

Spatially Referenced Data

Many integrated planning processes benefit from the ability to associate modeled assets with specific locations. As discussed in the chapter "The Integrated Planning Framework," a recurring theme in the stages of integration is aligning inputs and outputs across energy modeling domains. This process is often streamlined by visualizing and spatially overlaying assets. More fundamentally, integrated planning frequently seeks to understand where impacts and benefits occur within a system. For example, the placement of generation assets influences transmission system investments (see the section "Integration of Generation and Transmission Planning"). The ability to spatially analyze and visualize planning results is crucial.

Interoperability Across Modeling Domains

Integrated planning requires seamless data exchange across different modeling domains. Two primary approaches have emerged to address this challenge: information models and data exchange protocols.

- **Information models:** These models assume that different planning areas represent the same underlying energy system at varying levels of aggregation or disaggregation. A hierarchical data structure enables different domains to extract relevant details, while keeping the full model intact. For example, a common model might store positive-sequence reactance and susceptance values, which can be used in both ACPF modeling (reactance, resistance, and susceptance) and PCM (reactance only).
- **Data exchange protocols:** Instead of modeling the entire system, this approach standardizes only the information required to transfer data between domains. However, the energy industry has long struggled with data exchange standards, as they often become obsolete over time. Initial designs frequently omit key elements that were not recognized as important until later, limiting the designs' long-term viability. To address this, future data exchange solutions must incorporate intrinsic flexibility—potentially by drawing on lessons from other industries that have successfully developed adaptable interoperability frameworks.

Each method has trade-offs, and both remain emerging technologies with limited industry-wide adoption at this time.

High Dimensional Data Processing

Compared to traditional planning, integrated planning generates significantly larger datasets across multiple dimensions. These datasets must be processed to extract actionable planning insights. For example, conventional planning might analyze a single parameter across all system nodes (spatial dimension) under peak load conditions, whereas integrated planning may examine multiple parameters (parameter dimension) at each node (spatial dimension) over an entire year (temporal dimension) across various scenarios (scenario dimension).

To manage this complexity, emerging technologies include:

- **Interactive visualization tools** that allow users to explore results intuitively without saturating them with too much detail.
- **Statistical and machine-learning algorithms** for automated post-processing and pattern recognition.
- **Scenario reduction and clustering techniques** that intelligently pre-process input data by selecting a representative subset of scenarios, balancing computational efficiency with capturing the full range of possible conditions.

Computational Performance

As integrated planning explores more scenarios and in greater detail, computational demands increase. Efficient performance is essential to keep pace with this growing complexity. Emerging solutions include:

- **Secure cloud computing**, which provides scalable and secure processing power on demand.
- **Graphical processing units (GPUs)**, which offer a cost-effective means of accelerating computations. However, ongoing research is still assessing the feasibility of using GPUs for power-planning-specific applications.
- **Parallelizable workflows**, which allow computationally expensive workflows to be run within tractable time frames. Multi-model frameworks can significantly enhance computational performance by managing workflows across various models. This includes workflow management, co-simulation, automated iteration, and co-optimization frameworks, which can help improve both computational efficiency and the overall modeling process.

Multi-Model Interactions

The various software concepts used in integrated planning often require careful coordination to ensure smooth workflow management and efficient data exchange. Currently, this coordination is frequently achieved through significant manual effort, with custom scripts used to interface between different tools. Emerging solutions aim to streamline and automate these processes, including:

- **A single software paradigm**, an approach that offers a tightly integrated user experience but often requires migration to a new software ecosystem
- **A workflow management paradigm**, a method that preserves established tools while fostering collaboration but may introduce inconsistencies in modeling assumptions and data transfers

This chapter explored key software concepts for integrated planning and is followed by a discussion of the organizational structures and processes needed to put it into practice.

A Leadership Perspective on Integrated Planning

Much of this guidebook has focused on technical challenges and approaches to integrating various elements and practices of electricity system planning. There are also considerations for utilities and other entities wishing to integrate disparate planning areas.

Organizational Considerations

Electricity industry restructuring and the related sale of generation and transmission assets beginning in the 1990s led to the decentralization of electricity planning responsibilities. In some cases, regional system operators have assumed critical resource adequacy and transmission planning areas. While vertically integrated utilities remain intact, they began planning different levels of the electricity system separately in response to regulatory requirements (FERC vs. state).

While a strong case for re-integrating planning processes is evident, separation of planning areas into different departments within utilities (or even separate companies)—which use different software and data—means that significant institutional inertia needs to be overcome. There is often no single executive overseeing all the relevant functions (generation planning, transmission planning, etc.). In many cases, this responsibility falls to the president or chief executive officer. In other words, the person who could push for a change in planning is typically a senior executive already juggling numerous other priorities.

The processes by which generation, transmission, and distribution assets, and customer programs and resources have historically been planned have focused on meeting established reliability standards at least cost *at each level.* The industry has institutionalized practices that worked for many years. Individuals in these roles have often performed these functions for decades and lack visibility into and understanding of other planning areas.

Aligning planners from different functions requires thoughtful change management and a clear communication of shared goals. While this integration may initially be met with resistance, it ultimately fosters stronger coordination, reduces redundancy, and leads to more agile and informed decision-making—key advantages in today's fast-paced planning environment.

Aligning planners with expertise in different planning areas ultimately fosters stronger coordination, reduces redundancy, and leads to more agile and informed decision-making—key advantages in today's fast-paced planning environment.

Where to Begin

A compelling case for integration across electricity planning is critical. This guidebook lays out many of the reasons—see in particular the chapter "The Value of Integrated Planning." Each utility needs to determine for itself the case for integration, including defining the benefits. The approach to starting this journey, described in the chapter "The Integrated Planning Framework" (walk/jog/run), identifies some key activities where utilities can focus. Each utility, with its unique history, jurisdiction, market structure, and state regulatory environment, will have capabilities it can build upon and others it needs to develop. The framework and discrete steps described in the chapter "The Integrated Planning Framework" can guide utility leaders—and others—to the initial steps that will be most valuable.

A unifying rationale across utilities and other electricity planning entities is to identify the most reliable solutions at the least cost, considering risks and uncertainties. Some jurisdictions require additional objectives, such as increased deployment of cost-effective DERs (e.g., battery storage, load flexibility).

As an entity considers the journey to integrated planning, it may be beneficial to begin with a specific use case to test the concept. The organization's specific case for planning integration ideally meets one or more of the following criteria:

- Solves a real challenge the organization is facing
- Targets a critical issue while remaining achievable given existing staffing and resources
- Can be performed concurrently with existing planning activities
- Has a leader who will champion the effort and who has the authority to overcome organizational and process challenges
- Will share lessons about organization, process, and change management needed to further advance integrated planning
- Builds on at least one of the integrations described in this guidebook: generation/transmission, transmission/distribution, customer/distribution, or generation/distribution
- Is driven by a statutory or regulatory mandate

The planning integration case identified by the organization drives the data, technology, organizational, and process needs to conduct an integrated assessment. For instance, if a utility's charge is to identify the "least cost, best fit" use of storage for the transmission system and determine how it will impact generation needs, the utility could identify the generation and transmission planners who could perform this assessment. They would bring the tools and data from their particular planning areas and work together to identify where and when storage would be most beneficial. This could inform a financial analysis to support its implementation. The walk/jog/run approach described in "The Integrated Planning Framework" can help identify activities that will yield the greatest benefit. The next step is to identify key data, models, and individuals needed to perform a larger integrated study. The framework can also inform the organizational and process changes needed to more broadly integrate planning processes and functions.

Leadership and governance over the development of an integrated study is important. An internal champion needs the authority and resources to perform the study and extract from the effort the lessons necessary to further integration within the organization. Ideally, after demonstrating the value of integrated planning for the selected case, this individual will be able to advocate for integrated planning to the organization's leadership.

This approach starts the process to change the mindsets, strategies, and activities of those who participate, beginning the change management work that is necessary for these efforts to succeed.

Moving Forward

As utilities and other stakeholders in the electricity industry realize the need for integrated planning, they will need to build critical capabilities. These include:

- New organizational or governance structures
- Redefined processes to enable integration of critical functions
- Processes to manage and share data to support studies
- Implementation of new tools and other technologies

For organizations starting this journey, it is important to begin with a manageable case that builds on one of the walk/jog/run models described in this guidebook. Integration of planning processes is critical to maintain reliable and affordable electricity systems that accommodate a variety of generation, distribution, transmission, and customer assets.

Conclusion

The increasing complexity of modern power grids requires a more substantive incorporation of operational details—the practical system dispatches and associated constraints of future system portfolios—into long-term planning exercises. Traditionally siloed methods are no longer sufficient to address the multifaceted challenges posed by policy and regulatory changes, technological advances, extreme weather events and other reliability and resilience threats, and evolving customer needs. Integrated planning offers a structured methodology to ensure that planning efforts are comprehensive, adaptive, and forward-looking.

The framework in this guidebook for integrated planning progresses through *walk*, *jog*, and *run* stages, enabling planners to build trust, align assumptions, and eventually implement fully integrated models. By applying this staged approach, organizations can enhance grid reliability, optimize investment decisions, and efficiently incorporate new technologies. The structured approach outlined here empowers planners to address uncertainties with greater flexibility while improving coordination across planning areas.

Integrated planning is not just a technical exercise—it is an organizational shift. Successful adoption requires strong leadership, cross-functional collaboration, and a commitment to breaking down traditional silos. The leadership perspective offered in this guidebook highlights the key steps necessary to drive these advances, providing a practical roadmap that utilities, policymakers, regulators, and industry stakeholders can use to implement meaningful change in power system planning in step with evolving energy systems.

By embracing integrated planning, the power sector can move toward a more resilient, efficient, and affordable future.

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Integrated Planning Guidebook: A Practical Coordination Framework for Electricity Planners

A Report by the Energy Systems Integration Group's Integrated Planning Task Force

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This report and its companion reports are available at https://www.esig.energy/integrated-planning/.

To learn more about ESIG's work on this topic, please send an email to info@esig.energy.

The Energy Systems Integration Group is a nonprofit organization that marshals the expertise of the electricity industry's technical community to support grid transformation and energy systems integration and operation. More information is available at https://www.esig.energy.

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