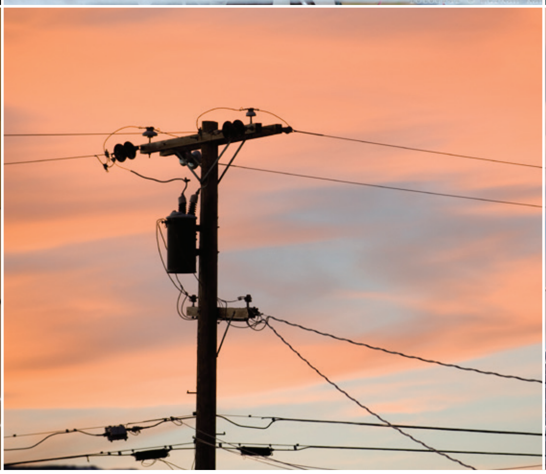
Foundations of Integrated Planning

DEFINING A FRAMEWORK FOR COMPREHENSIVE ENERGY SYSTEM PLANNING








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

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ESIG
ENERGY SYSTEMS
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Foundations of Integrated Planning: Defining a Framework for Comprehensive Energy System Planning

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

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Disclaimer

This report was produced by a task force made up of diverse members with diverse viewpoints and levels of participation. Specific statements may not necessarily represent a consensus among all participants or the views of participants' employers.

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Executive Summary

Traditional electricity planning practices have often been siloed. Generation, transmission, distribution, and customer program/distributed energy resource (DER) planners all have their own planning teams, models, data inputs, and vocabularies. This siloed approach was sufficient when one-way power flow from a limited set of dispatchable generators allowed for either separate or sequential planning processes with limited feedback between them. However, that is not the power system of today. Ongoing transformations—including accelerating load growth, technology development, the growth of inverter-based resources, evolving extreme weather events, and the emerging need to consider integrations between coupled energy systems—are pushing planning processes toward a new integrated planning paradigm.

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, and distribution, and customer loads and DERs, and may also consider interactions between the electricity system and other energy systems. This type of planning can ensure the right investments, in the right places, at the right times, and has the potential to lead to a lower-total-cost set of solutions to meet planning needs.

A four-part integrated planning framework is presented in this report (Figure ES-1, p. viii). The **integration of inputs** focuses on aligning inputs, modeling assumptions, scenarios, and data formats and structures across planning

FIGURE ES-1

The Integrated Planning Framework Presented in This Report

Integration of Inputs	Integration of Analysis	Integration of Actions	Integration with Decision-Making
Aligning inputs, modeling assumptions, scenarios, and data formats and structures across planning processes to set a common foundation across all planning processes	Determining the key data flows between both economic and physical planning analyses needed to reach a comprehensive solution	Leveraging integrated planning analyses to determine a coordinated set of near-term proposed investments across all planning domains	Ensuring that these proposed near-term action plans fit within existing infrastructure decision-making structures or that those decision-making structures evolve to support regulatory approval and implementation of comprehensive planning solutions

Source: Energy Systems Integration Group.

processes to set a common foundation. The **integration of analysis** emphasizes determining the key data flows between both economic and physical planning analyses needed to reach a comprehensive solution. Data flows are mapped within electricity generation, transmission, and distribution and customer program/DER planning, as well as between electricity planning, natural gas system planning, and economy-wide decarbonization analyses. Integrated analysis can be achieved through co-optimization across planning domains (such as capacity expansion that considers generation, transmission, and storage investments) or iterative processes focused on two flows of information between models. The **integration of actions** involves leveraging integrated planning analyses to determine a coordinated set of near-term proposed investments across all planning domains. The **integration with decision-making** ensures that these proposed near-term action plans fit within existing infrastructure decision-making structures or that those decision-making structures evolve to support regulatory approval and implementation of comprehensive planning solutions.

In addition to substantial technical changes to analytical processes, integrated planning involves change management and can benefit from an incremental approach. While the journey will be unique within each planning process, most can benefit from the following generalized set of steps:

- Determine integrated planning objectives
- Perform a gap assessment for existing planning processes
- Align key inputs and develop integrated scenarios

In addition to substantial technical changes to analytical processes, integrated planning involves change management and can benefit from an incremental approach.

- Develop deeper connections between existing analytical processes
- Create or adapt stakeholder engagement plans to support an integrated planning process
- Consider organizational re-alignment and/or formalized agreements between planning organizations
- Advance new analytical methods and tools to facilitate planning integrations
- Consider opportunities for co-optimization or co-simulation methods across planning domains

Technology and policy drivers are pushing planners toward a more integrated approach. The framework presented in this report forms a foundation upon which planners can build to reap the benefits of new comprehensive planning methods. While each integrated planning process presents its unique opportunities and challenges, all processes can improve by strengthening their technical and procedural connections across planning domains.

Introduction

Planning is a foundational aspect of building a reliable and affordable power grid, ensuring sufficient generation capacity to meet demand as well as the necessary grid infrastructure to securely and efficiently deliver power through the bulk transmission and local distribution systems. Even in "deregulated" markets, long-term planning remains essential to evaluating transmission and distribution grid investments. A confluence of factors is now driving electricity system planners to consider the need for deeper integration across traditionally siloed planning processes, models, and—in some jurisdictions—organizations. **Rapidly accelerating load growth** from electrification, data centers, and new industrial loads is stressing the ability of the generation system and the grid to serve new loads in a timely manner. **Technology evolution** is unlocking new investment options for the bulk grid (battery storage, emerging generation technologies, transmission grid-enhancing technologies) and local grids (distributed energy resources (DERs), electric vehicle vehicle-to-grid integration, and flexible loads). Some of these can be built more quickly than traditional investments (battery storage), and others take significantly longer to build (offshore wind). **Aging infrastructure** will require replacing critical components of the 20th century grid, and these improvements will need to be coordinated with grid expansion needs.

Inverter-based resources such as solar, wind, and battery storage displace synchronous generators that traditionally were relied upon for grid stability, leading to the need for more stability analyses and mitigations (inverter-based resource controls tuning, grid-forming inverters, synchronous condensers). In some jurisdictions, **decarbonization of the power grid and other sectors of the economy** is being driven by mandated or voluntary emissions reductions goals by nations, states, utilities, and/or major corporations, and has the potential to transform the way energy is produced and delivered. In other jurisdictions, new low-carbon technologies are being adopted in the absence of policy mandates, driven by economics alone. There is also a need to consider **integrations across coupled energy systems**, such as the electricity grid and its interactions with fuel and potential future carbon pipeline networks, which may be of increasing importance in the future. All these drivers are occurring amid **evolving extreme weather events**, including wildfires, heat waves, and droughts, that may impact the study conditions for planning decisions or the resilience value of new infrastructure. Continued **advances in planning models and cloud computing capabilities** have also expanded the toolkit available to electricity planners.

The Energy Systems Integration Group convened a task force of experts from utilities, system operators, research organizations, national labs, consultants, and other planning practitioners to define integrated planning opportunities and document practical steps planners can take toward a comprehensive planning approach. A series of task force meetings were held, which culminated in three reports to contribute to the nascent knowledge base of integrated planning practices. First, this report, *Foundations of Integrated Planning*, defines integrated planning and discusses the need for it, followed by a broadly applicable framework for comprehensive planning. The second and third reports focus specifically on electricity system planning integrations. The second report, the *Integrated Planning Guidebook*, 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 challenges for using economic optimization capacity expansion modeling to consider a broader set of integrated planning constraints and investment opportunities.[1]

Traditional Planning Processes

While some planning processes have considered varying degrees of integration, power system planning has traditionally been siloed into a core set of disciplines. Each planning discipline has its own team of experts, vocabulary, datasets, modeling tools, physical and/or economic constraints, and regulatory structures for decision-making. The constraints that planners must conform to are often set by national, regional, or state organizations (such as the North American Electric Reliability Corporation (NERC) or state public utility commissions), though these standards may be complemented by additional organization-specific objectives.

The one-way flow of power in historical systems meant that siloed planning could generally proceed in sequence from generation planning to transmission planning to distribution planning, with limited—if any—backwards flow of information into prior planning processes.

Integrated planning is defined as 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.

Historically, power systems were planned for a one-way flow from bulk grid generators, through the transmission system, then through the distribution system to serve retail electric loads. The one-way flow of power in these historical systems meant that siloed planning could generally proceed in sequence from generation planning to transmission planning to distribution planning, with limited—if any—backwards flow of information into prior planning processes. While some opportunities may have been missed, siloed planning was generally sufficient when investments in one planning domain had limited impact on (or the ability to support) other planning needs.

Table 1 (p. 3) describes key aspects of traditional planning processes for electricity generation, transmission, distribution, and customer programs and DERs. These aspects include the planning horizon, analytical tools, planning constraints that drive investment needs, traditional investments available, and new types of investments and emerging challenges that are driving the need for planning integration within and across disciplines.

Defining Integrated Planning

Integrated planning can be defined narrowly as between specific planning domains, such as integrated generation and transmission planning, or it can be defined broadly to encompass all potential energy system integrations. This report proposes the following broad definition:

1 The present report, the *Integrated Planning Guidebook: A Practical Coordination Framework for Electricity Planners*, and *Optimization for Integrated Electricity System Planning: Opportunities for Integrated Planning in Capacity Expansion Models* can all be found at https://www.esig.energy/integrated-planning/.

TABLE 1

Traditional Electricity Planning Processes and Emerging Challenges

Planning Process	Timelines	Analytical Methods/Tools	Planning Criteria	Traditional Investments	New Investments	Emerging Topics/ Challenges
Generation resource planning	Occurs every 2 to 5 years Planning horizon of 10 to 25 years	Optimal capacity expansion Loss-of-load probability analysis Zonal and/or nodal production cost modeling Flexibility analysis	Clean energy policy Resource adequacy Operational reliability and flexibility Least-cost economics	Dispatchable thermal resources (natural gas, coal, biomass, etc.) Nuclear Hydroelectric power Geothermal Demand response	Solar Wind (onshore and offshore) Battery and long-duration energy storage Natural gas or coal with carbon capture and storage Hydrogen turbines Load flexibility and virtual power plants	Evolving resource adequacy needs Increasing operating reserve requirements Climate change impacts Common mode failures Renewable energy droughts Inverter-based resource integration
Transmission planning	Occurs every 1 to 3 years Planning horizon of 5 to 15 years	Nodal production cost modeling Steady-state power flow Dynamic stability studies Contingency analysis Short-circuit analysis and protection coordination	Asset health Thermal limits Voltage limits Stability limits Economics	Power lines Substations and transformers Protection and control equipment Series compensation Static and dynamic reactive compensation Synchronous condensers	Storage providing transmission service Advanced transmission technologies (advanced conductors, dynamic line ratings, power flow controllers, etc.) Grid-forming inverters Extra-high-voltage and high-voltage DC transmission	Low-inertia systems Weak-grid issues Proactive investment for remote generators Siting and permitting Interconnection backlog and delays Interregional transmission needs
Distribution planning	Occurs every 1 to 3 years Planning horizon of 3 to 10 years	Peak load forecasting Power flow analysis Short-circuit analysis and protection coordination	Asset health Thermal limits Voltage limits and power quality Protection Safety	Distribution lines Substations and transformers Protection and control equipment	Storage providing transmission distribution service Smart inverters, conservation voltage reduction, volt/VAR optimization Distributed energy resource management systems	Uncertainty in location and timing of load growth, including electrification Need to extend planning horizon versus traditional near-term investment focus
Customer programs and distributed energy resource (DER) planning	Occurs every 1 to 3 years Planning horizon of 2 to 5 years	Avoided costs and cost-benefit analysis Program design Tariff and rate design	Cost-effectiveness Equity Market transformation Clean energy policy	Energy efficiency Demand response Tariff and rate design	Behind-the-meter solar, storage Flexible loads (including electric vehicle charging) Virtual power plants	Load and distributed energy resource forecasting (how much, when, where) Advanced rate design Distributed energy resources operational control Value stacking and value sharing across operational domains

Overview of traditional electricity generation, transmission, distribution, and customer programs and DER planning processes, including their timelines, methods, tools, planning criteria, traditional and novel investment options, and emerging challenges.

Source: Energy Systems Integration Group; adapted from A. Burdick, J. Hooker, L. Alagappan, M. Levine, and A. Olson, *Integrated System Planning: Holistic Planning for the Energy Transition*, Energy and Environmental Economics, Inc. (2024), https://www.ethree.com/wp-content/uploads/2024/10/E3-ISP-Whitepaper.pdf.

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.

The Need for Integrated Planning for Electricity Systems

The electric power system is core to the foundation of a modern economy. Electric loads are growing across the world. In the United States, for example, after a period of relatively flat loads associated with increasing energy efficiency and a slowdown of industrial growth, electric load growth is now projected to reach nearly 5% annually over the next five years.[2] In the long run, the potential for electrification of buildings, transportation, and industry means that the electric power system will be even more foundational to serving the energy needs of the 21st century. The combination of electric load growth with mandated or voluntary decarbonization policies is driving a transformational change in loads, generation capacity growth, and transmission needs, as the need grows for both renewable energy resources (remote as well as local) and the associated grid delivery infrastructure.

Changing Grid Needs and Investment Opportunities

New technologies like energy storage, grid-forming inverters, virtual power plants, flexible electric vehicle charging, distributed energy resource management systems, and grid-enhancing transmission technologies are changing the investment opportunities available for power system planners. They are also creating increased opportunities for value stacking/sharing across different operational and regulatory domains. A classic example is behind-the-meter battery storage that can provide customer bill savings, avoidance of distribution and transmission system upgrades, and bulk resource adequacy and renewable integration value. Investments with multiple value streams create exciting yet challenging opportunities for power system planners to consider how to integrate these options into traditional investment planning practices. For instance, to properly plan for behind-the-meter battery investment requires consideration of retail rate design and/or new customer programs, distribution system planning and operations, generation resource adequacy, and a challenging quantification of the economic value of avoided bulk grid generation and transmission investments.

Wind and solar resources can drive the need for operational paradigm shifts, such as planning to serve peak net load conditions and needing to define minimum secure net load levels. They are often located far from load centers and therefore require significant transmission investments, which can alter the topology of the transmission grid. IBRs, including solar and wind as well as battery energy storage, can have an impact on various aspects of dynamic stability, and evaluating and planning for mitigations spans across all of today's planning silos. IBRs can impact transfer limits on transmission lines and can displace synchronous generators that are providing reliability services such as inertia or frequency response. IBRs may have trouble synchronizing in weak grids, which may be the result of high shares of IBRs displacing synchronous generators. Adjacent IBRs may have adverse control interactions, especially under weak-grid conditions, leading to oscillations on the grid. In regions where these issues are occurring, new types of stability analyses are now required. Mitigations may include new investments such as for synchronous condensers or grid-forming inverters, or new operating limits such as curtailment of wind and solar to keep a minimum level of synchronous generation online. These mitigations would then need to be included in planning, for example, adding synchronous condensers to a capacity expansion plan or putting additional operating limits into a production cost model, which requires a two-way flow of information between generation planning and transmission planning.

These changes are impacting the viability of historical planning processes within and across each planning domain. For example, within generation planning,

2 J. D. Wilson and Z. Zimmerman, *The Era of Flat Power Demand Is Over* (Grid Strategies, 2023), https://gridstrategiesllc.com/wp-content/uploads/2023/12/National-Load-Growth-Report-2023.pdf.

TABLE 2

Example Impacts of Siloed Planning of Electricity Systems

Planning Domain Interactions	Misalignment from Siloed Planning	Impact
C ←→ G/T/D	If distributed energy resources and flexible loads are not considered as generation or transmission and distribution grid resources . . .	. . . this may lead to over-reliance on grid and bulk generation investments and increased ratepayer costs.
	If valuation of customers' distributed energy resources is not aligned with the bulk grid investments they help to avoid . . .	. . . this may lead to incorrect estimation of customers' resources' cost-effectiveness and thus to under- or over-adoption.
T → G	If transmission upgrade costs and build timelines are not properly incorporated into generation planning . . .	. . . a sub-optimal generation (and transmission) portfolio may be selected at a higher cost than a co-optimized portfolio.
G → T	If changing risk periods from evolving resource mixes are not studied in transmission models . . .	. . . transmission deliverability and stability studies may miss required upgrades or make upgrades in the wrong locations.
Storage ←→ G/T/D/C	If the grid benefits of storage siting are not considered . . .	. . . storage siting may miss opportunities for grid investment deferral or other potential value streams.

Capturing interactions between planning domains can avoid the misalignments from siloed planning and lead to more optimal, cost-effective investment decisions.

Notes: G = generation, T = transmission, D = distribution, C = customer programs and distributed energy resources.

Source: Energy Systems Integration Group.

measuring resource adequacy contributions now requires simulating all generating resources together, as performed in effective load-carrying capability (ELCC) studies. Between planning domains, as power system needs and investment solutions become more interdependent, the application of historically siloed planning practices will lead to sub-optimal outcomes. Examples of these outcomes are shown in Table 2.

Interdependence of Integrated Electricity System Planning

Figure 1 (p. 6) shows the interdependent nature of integrated electricity system planning. Generation planning is coordinated with distributed energy resource investments and transmission upgrades needed for new bulk grid generators. Transmission planning is coordinated with generation investment plans and distribution system planning. Avoidable transmission and distribution grid investments inform the valuation of DERs relative to bulk grid investments. Distribution planning is coordinated with DERs' investment opportunities, their operations, and transmission system needs and modeled conditions.

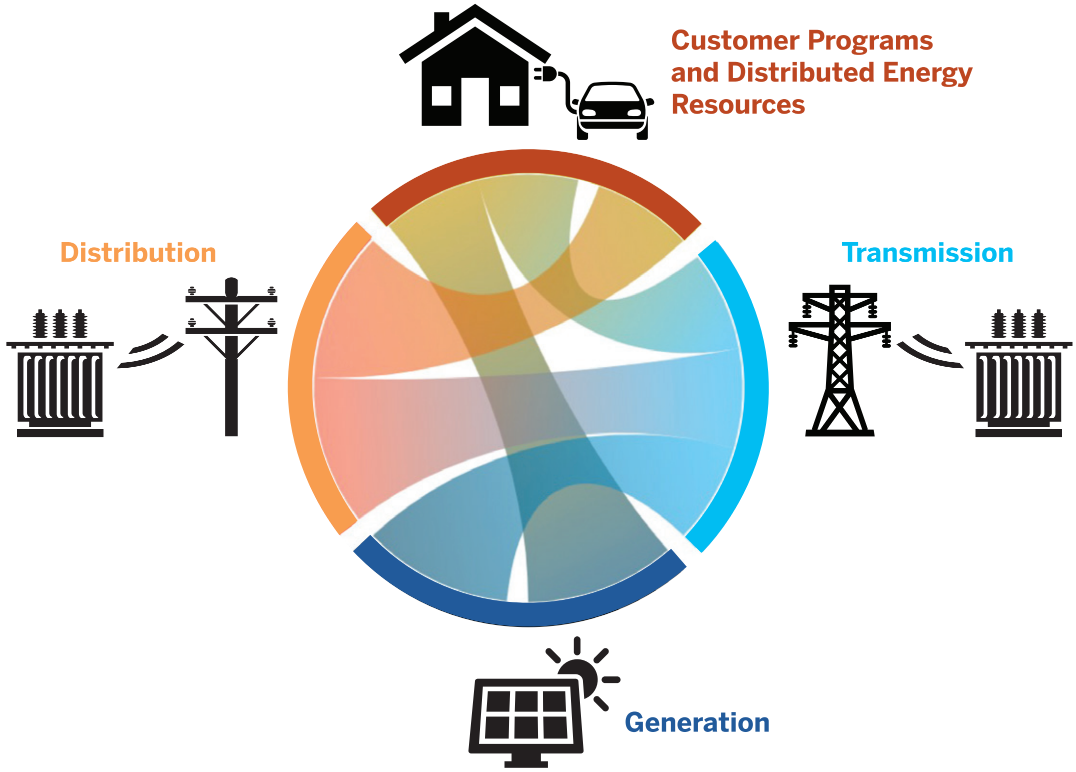
The outcome of an integrated planning process is a set of investments that are made in the right places at the right times, as illustrated in Figure 2 (p. 7). Establishing a robust planning process that (A) considers a broad range of resource and grid investments, (B) incorporates their spatial locations relative to locational system needs, and (C) considers realistic estimates of when those options are available across the planning horizon and during which hours they can support system needs, provides the foundation for determining comprehensive planning solutions.

The Need for Integrated Planning Between Electricity Systems and Other Energy Systems

In many places today, there is limited coordination between electricity system planning processes and the planning for other key components of economy-wide energy systems. As natural gas power plants have grown in their importance for electric power reliability, there is an increasing need to consider the constraints of the natural gas delivery system in power system planning.

FIGURE 1

Integrated Electricity Planning



An integrated planning process showing links between generation, transmission, distribution, and customer programs and DER planning.

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

In addition, various economy-wide sectors such as buildings, transportation, and industry have widely varying levels of regulation and planning. Where economy-wide decarbonization policy goals exist, a crucial aspect of policy implementation is to conduct economy-wide scenario analysis for how to meet those goals in a feasible, timely, and affordable manner. These studies have key synergies with both electricity system planning (the level of electric load growth and associated infrastructure needs and costs, what level of electricity decarbonization is consistent with a net-zero carbon economy, etc.) and natural gas system planning (decarbonized fuel production and delivery, cost recovery and customer equity considerations with declining gas throughput, etc.). The need for cross-sector planning may also emerge for grids that do not have cross-sector decarbonization policies but may still have increasing levels of hydrogen or other zero-

FIGURE 2

Key Outcomes from Integrated Planning

	Examples
Right investments…	• Optimal mix of dispatchable thermal, renewable, and storage resources to meet reliability and policy goals • Investments in load flexibility versus utility storage • Grid investments versus non-wires alternatives
…in the **right places**…	• Geospatial forecasting of load growth, distributed energy resources, and resource potential • Optimal siting of storage resources on the bulk grid, distributed in-front-of-meter or distributed behind-the-meter • Where to build new transmission infrastructure to support reliability, economic, and policy objectives
…at the **right times**	• Proactive grid build-out to support electrification or new large loads • Consistent investment signals for the marginal hourly value of generation between bulk grid planning, customer program and distributed energy resource valuation, and retail rate design

Integrated planning strives to make the right investments in the right places at the right times. Establishing links between investment options and their ideal spatial locations and temporal output is what allows integrated planning to achieve comprehensive, lower-cost planning solutions.

Source: Energy Systems Integration Group.

TABLE 3

Example Impacts of Siloed Planning of Electricity, Gas, and Other Energy Systems

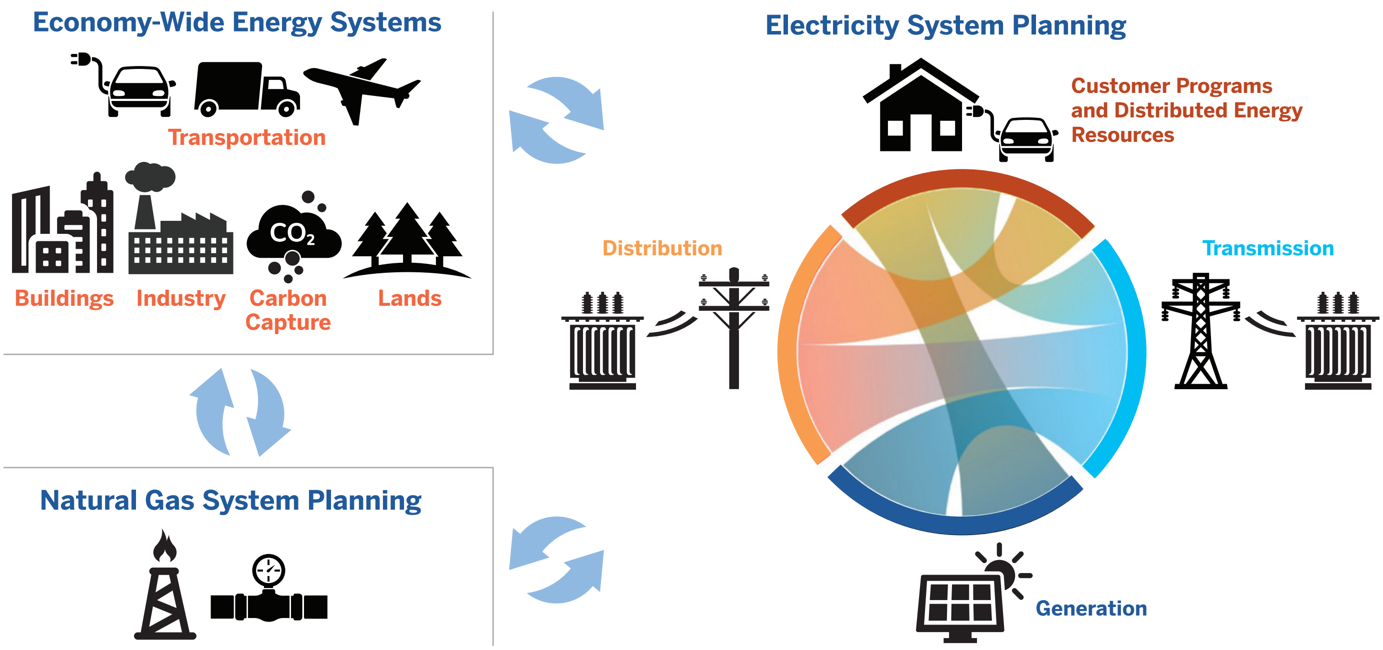
Planning Domain Interactions	Misalignment from Siloed Planning	Impact
Natural gas ←→ electricity	If natural gas system delivery constraints are not considered in modeling of electricity system reliability and markets . . .	. . . plants may fail or have insufficiently firm gas supply during critical reliability events.
	If building electrification is not coordinated with strategies for managing gas pipeline assets . . .	. . . both electric appliance adoption and gas system cost recovery may face affordability and equity challenges.
Economy-wide ←→ electricity	If forecasts of electrification and industrial load growth are absent from power system planning . . .	. . . load interconnections and associated economic development or carbon reductions may be delayed by generation capacity or interconnection constraints.
Economy-wide ←→ natural gas	If fuel switching and decarbonized gas scenarios are not considered in long-term planning . . .	. . . throughput declines or alternative fuel opportunities may be insufficiently explored.

Capturing interactions between electricity planning and other energy systems can avoid the misalignments from siloed planning.

Source: Energy Systems Integration Group.

FIGURE 3

Integrated Planning Across Electricity, Natural Gas, and Other Economic Sectors



Links between economy-wide energy systems, natural gas system planning, and electricity system planning.

Source: Energy Systems Integration Group (left), Energy and Environmental Economics (E3) (right side).

carbon fuel production, which require coordination of production, transportation, and storage infrastructure. Table 3 (p. 7) provides examples of the suboptimal outcomes of siloed planning of electricity systems, gas systems, and other economy-wide sectors.

Figure 3 builds on the integrated electricity system planning diagram in Figure 1 (p. 6), showing the additional opportunities for comprehensive planning with economy-wide energy systems and natural gas system planning.

An Integrated Planning Framework

The remainder of this report outlines the key components of an integrated planning framework drawing from the expertise and experience of the members of ESIG's Integrated Planning Task Force. The key components are:

- **Integration of inputs:** Aligning scenarios, input assumptions, and data as the foundation for integrated planning
- **Integration of analysis:** Using co-optimization and/or iterative processes to reach a comprehensive set of solutions that meet affordability, reliability, and policy goals
- **Integration of actions:** Using planning results to guide near-term investment actions
- **Integration of planning with decision-making:** Aligning planning activities with business and regulatory decision-making processes

The report concludes with a short overview of how planners can move incrementally toward a fully integrated planning process.

Integration of Inputs

An integrated planning process starts with the development of key assumptions that drive all later modeling. These include determining planning scenarios to be studied, the planning horizon to be used, inputs and assumptions for key parameters, and data definitions and formats.

Planning Scenarios

Scenario planning is a crucial aspect of many existing electricity planning processes. Generation planning processes, also known as integrated resource planning (IRP) processes, tend to consider a broad range of scenarios during capacity expansion modeling or follow-on cost and risk analyses. Transmission planning analyses tend to consider fewer scenarios with broad changes in loads and resources mixes, but may consider various transmission reliability scenarios with one or a couple of resource build-out and retirement scenarios, as well as many regional scenarios of transmission and/or generation outages. Distribution planning processes historically have focused on a single planning scenario of near-term load and distributed energy resource growth to determine near-term distribution investment decisions. Customer programs and distributed energy resource planning tends to use a single set of avoided costs that may drive multiple scenarios of DER adoption by varying resource costs, key adoption criteria, or cost-effectiveness thresholds.

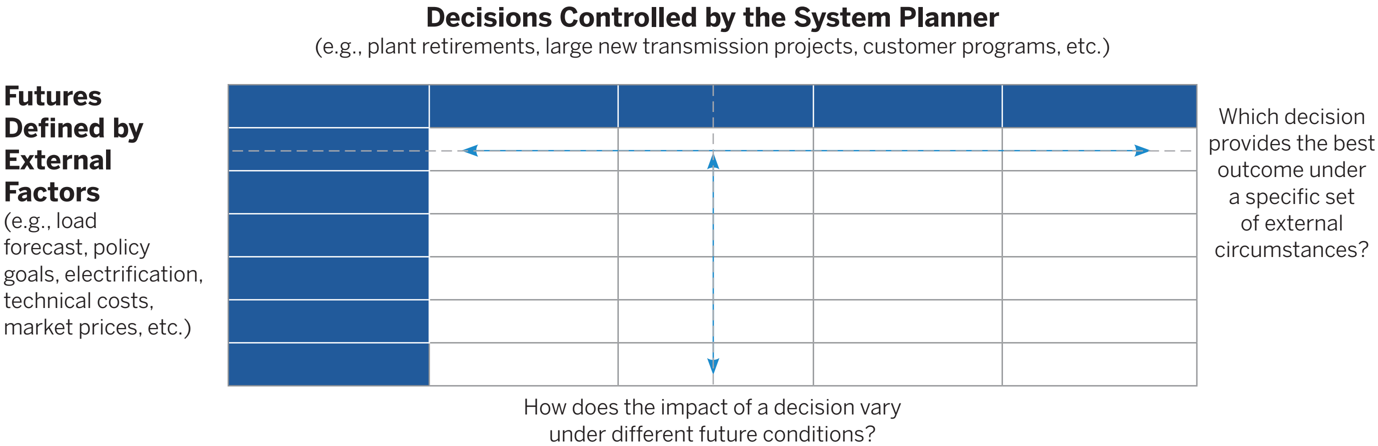
While integrated planning does not necessitate using the same full set of scenarios across all planning processes, it does require alignment on a set of core scenarios of load growth and other key input assumptions across planning models. Within each planning domain, sensitivities to these scenarios may be explored to inform robust planning. For example, a core set of load scenarios can be studied across all planning processes, such as a low, medium, and high levels of load growth, informed by DER adoption, electrification, and other key drivers. Each planning process may then consider key sensitivities that impact the demand for the amount and type of investments needed in each planning domain. The use of specific load-growth scenarios will depend upon planning objectives that vary from region to region. For instance, transmission planning is often more conservative and may plan to a "high growth" scenario to ensure that asset sizing will not result in future costly capacity upgrades.

While integrated planning does not necessitate using the same full set of scenarios across all planning processes, it does require alignment on a set of core scenarios of load growth and other key input assumptions across planning models.

Considering a range of load scenarios can inform least-regrets planning. Within a given load scenario, generation planners may consider multiple scenarios of fuel prices, load shapes, resource availability and costs, and clean energy policies, whereas distribution planners may consider scenarios of *where* that load growth will be concentrated, load shapes for new types of loads (such as electric vehicles), and the level of DER adoption and control. Figure 4 shows one of many potential approaches to scenario design, providing a matrix of cases shown in the white table cells that are combinations of scenarios defined by external factors (load growth, policy goals, etc.) and scenarios of decisions controlled by planners (plant retirements, new transmission line construction, creation of new customer programs, etc.). Scenarios of

FIGURE 4

An Example of Defining Scenarios Based on External Factors and Planner-Controlled Decisions



Scenarios can be defined based on a combination of external factors and decisions under control of the planning entity. Each white cell in the table represents a potential scenario or sensitivity that could be studied in the planning process.

Source: A. Olson, J. Hooker, A. Burdick, and L. Alagappan, "Integrated System Planning: From Vision to Reality," Energy and Environmental Economics, Inc., ISP Webinar Series presented September 26, 2024.

long-term climate impacts should be aligned across all infrastructure planning processes.

Inputs and Assumptions

Alignment on core inputs and assumptions is a critical part of integrated planning. Planning requires many assumptions about the future state of a given power system, the local economy, macroeconomic changes that impact financing costs, and other core assumptions that drive investment needs and options. Key inputs to be aligned across planning processes include:

- Cost assumptions (resources, fuel, etc.)
- Load forecasts and load shapes
- DER potential and/or forecasts, production shapes, and/or operating characteristics
- Meteorological datasets of historical weather and climate change–driven adjustments
- Solar and wind production shapes
- Resource availability and potential
- System operational requirements (reserve requirements, frequency/voltage limits, etc.)
- Utility and third-party developer financing costs
- Financial discount rates

Planning Horizon

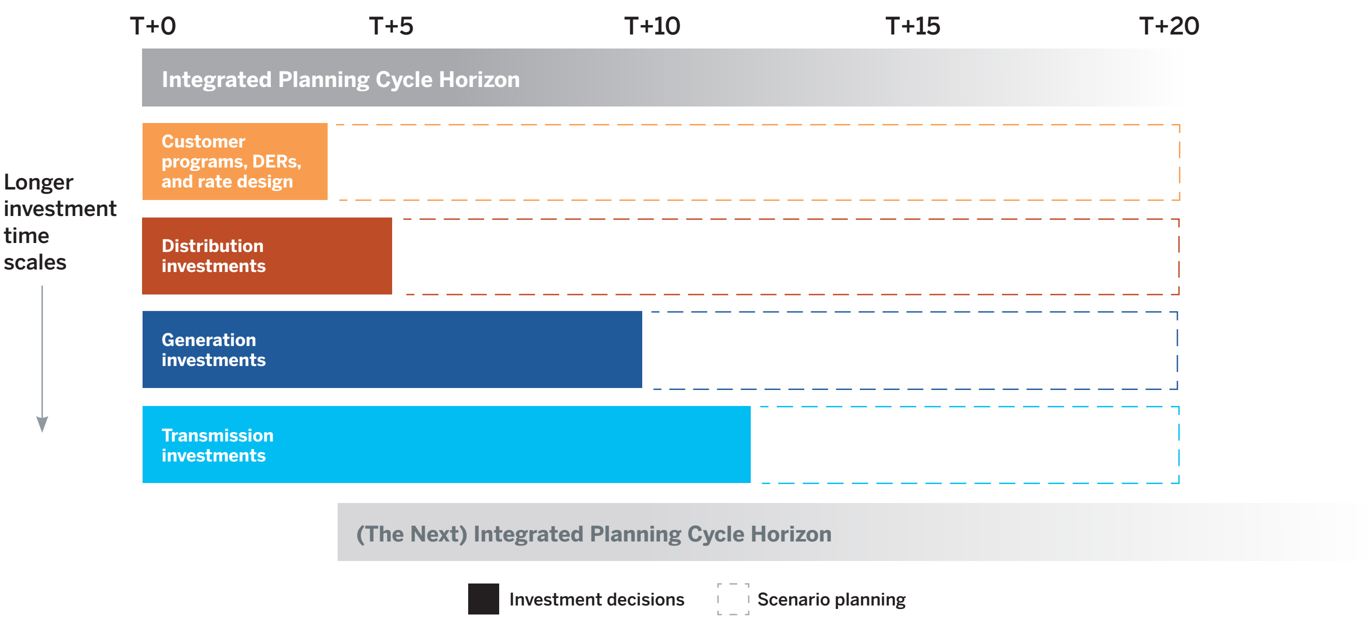
The planning horizon, the period over which a planning process analyzes investment needs, is often distinct from the investment period, the period during which a given planning cycle will consider investment needs. Infrastructure with significant lead times requires very long planning horizons. Transmission planning often looks 10 to 20 years forward to determine investments for transmission lines up to 10 to 15 years ahead of their expected commercial operations date. Generation planning processes tend to look 10 to 20 years forward for investments to support generation needs over the next approximately 5 to 7 years. Historically, distribution planning horizons tend to be shorter, as investments have shorter lead times and investment plans can be updated in the next planning cycle accordingly; this provides optionality to adapt investment plans between cycles as load and DER forecasts change. DER customer programs and retail rates/tariffs can be updated every couple of years.

In general, an integrated planning cycle needs to have a planning horizon of at least 15 to 20 years, to ensure that long-lead-time transmission and generation investments can be optimally determined together with consideration of shorter-lead-time investments. Some jurisdictions may look 25 years out (or even longer) and may structure phases of the planning process, where the first 5 to 10 years inform a relatively fixed set of discrete investments, and years beyond then consider a broader set of scenarios and solutions. These long horizons require distribution planners to consider longer-term planning and broader scenario planning more than has been typically done in the past, with that additional time horizon providing consideration of right-sizing investments for long-term needs even though specific investments may still be focused in the first five years. Alongside these new distribution planning practices, new investment frame-works are needed to support proactive grid investments and/or DERs for grid deferral in regions with growing loads. As shown in Figure 5, long-term scenario planning of core integrated planning scenarios is applied across all planning domains, while investment periods will have varying timelines depending on the planning domain.

Long-term scenario planning of core integrated planning scenarios is applied across all planning domains, while investment periods will have varying timelines depending on the planning domain.

FIGURE 5

A Sample Integrated Planning Horizon



Horizons for generation, transmission, distribution, and customer programs and DERs in an integrated planning process, segregated by the investment decision time frame in the current cycle and the scenario planning time frame beyond near-term investment decisions.

Source: Energy Systems Integration Group.

Data

Integrated planning requires a lot of data. Data are created as inputs into planning models and as output from planning models for input into downstream planning models. Since electricity generation, transmission, distribution, and customer program/DER planners tend to use different models, there is limited standardization today of data definitions and data formats. This creates challenges for the transfer of data between models that is necessary for integrated planning.

Since different planners tend to use different models, there is limited standardization today of data definitions and data formats, and this creates challenges for the transfer of data between models that is necessary for integrated planning.

Data definitions and formats should be consistent between models and planning processes. This includes consistency in defining time-series data (daylight savings and leap year treatment, etc.), spatial data mapping (using geographic information system (GIS) data coordinates and/or topological mapping of electrical grid components), real versus nominal dollars for financial analysis, measurement of load pre- or post-transmission and distribution losses, etc. Consistency should also be ensured in weather data underlying load and resource shapes, to appropriately capture correlations between meteorology/weather, energy demand, and energy supply. Automated scripts can reduce human effort and error in transferring data from one model's outputs into another model's inputs, although care must be taken to check data integrity, structure, and validity, which requires either human oversight and/or automated quality control checks. Data storage and sharing methods can be set up to facilitate efficient sharing of large datasets across multiple teams.

Integration of Analysis

Integrating historically siloed analytical processes is the core of an integrated planning process. Many planning processes have some level of integration; however, integrated planning requires consideration of two-way flows of information between models and/or co-optimization across planning domains within an individual planning model. The foundation for integrated analysis is determining the key information that needs to flow between each set of planning processes. That information can either flow endogenously by expanding the scope of traditional planning models or be passed between models exogenously in an iterative process to converge on a comprehensive planning solution. Either approach can be sufficient for integrated planning. The appropriate analytical design will differ for each planning process, based on the data available, the models used, the organization's capabilities and resources, and the associated regulatory requirements. The third report in this series, *Optimization for Integrated Electricity System Planning*, addresses the limits of endogenous optimization and presents iterative processes that function as practical alternatives.[3]

Integration Across Electricity, Natural Gas, and Economy-Wide Energy Demands

Increasingly, planners are recognizing critical connections between the planning of the electric power system and the needs and capabilities of other energy demands across the economy (Figure 6, p. 14).

Economy-Wide Energy System Planning

Planning for economy-wide energy systems refers broadly to analytical processes that consider energy demands across all sectors and end uses in the economy. Planning at this broad scale generally does not have the same institutionalized oversight or standardized analytical practices as electricity planning processes, which are often under direct regulatory oversight from state or federal regulators. In regions that have adopted economy decarbonization policy objectives, such as reaching a net-zero carbon economy, economy-wide analysis is critical to inform feasible and affordable decarbonization pathways to achieve those objectives. It is often performed by utilities with voluntary decarbonization goals or by government agencies charged with studying and implementing legislative directives. Due to the interactions between economic sectors, these analyses inherently consider sector-coupling, considering the benefits of coordinating decarbonization strategies between economic sectors. For example, sectoral coupling considers:

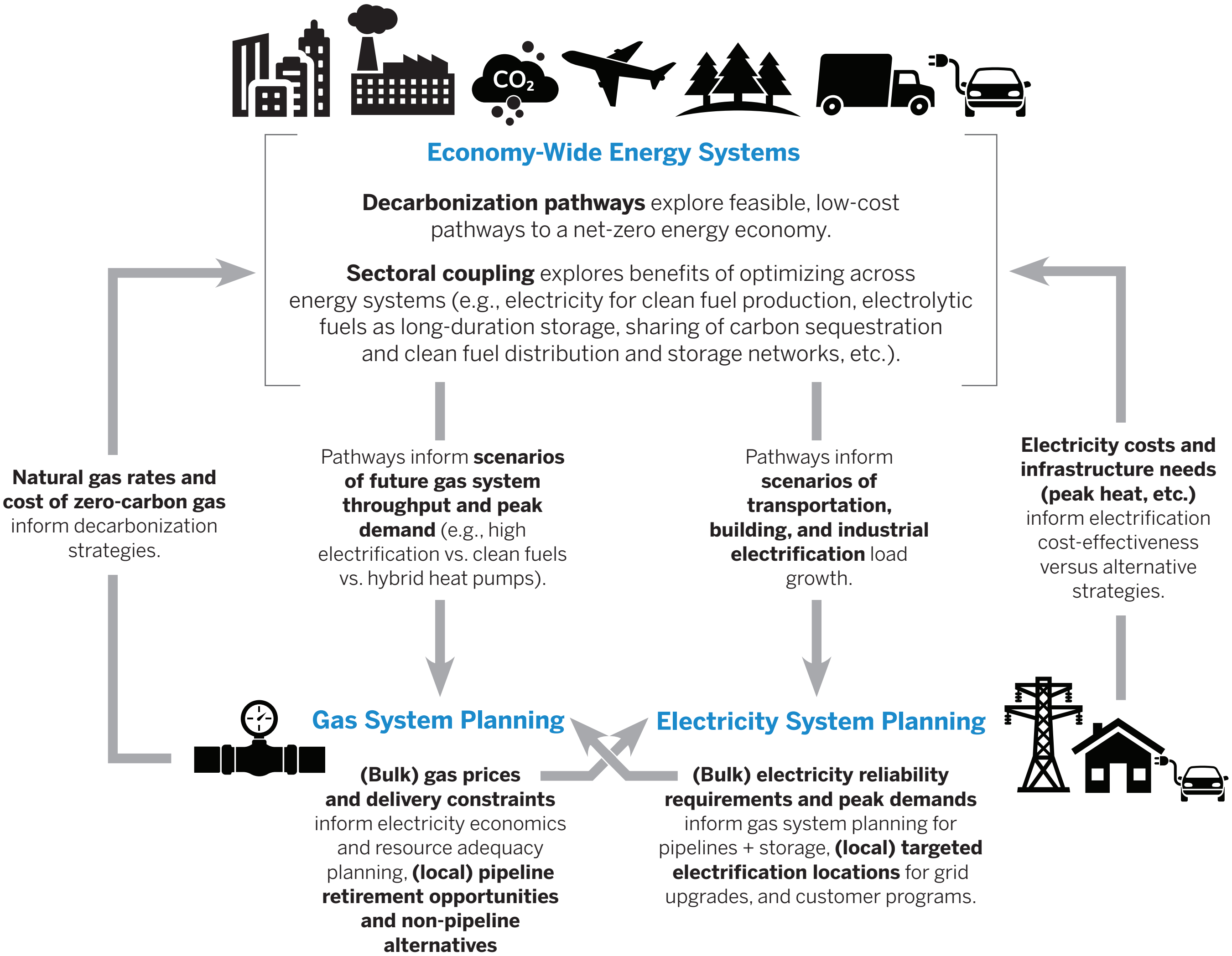
- **Optimal long-term policy targets between sectors,** such as electricity sector decarbonization targets that are consistent with reaching a net-zero carbon economy and electrification emissions benefits amidst increasingly lower-carbon electricity supply
- **Infrastructure needs in one sector to support decarbonization of another sector**, for example, electrification load growth, electricity and fuel distribution infrastructure needs for new decarbonized fuels, and optimization of the size and location of carbon capture, distribution, and storage networks

Consideration of these interactions between sectors to achieve feasible and affordable decarbonization pathways is a critical benefit of models that have the full economy-wide scope. Though some tools can optimize certain parts of the economy, these models often depend on

3 https://www.esig.energy/integrated-planning/.

FIGURE 6

Information Flows Between Electricity, Natural Gas, and Economy-Wide Energy System Planning



Key information flows between economy-wide energy systems, natural gas system planning, and electricity system planning.

Source: Energy Systems Integration Group.

users to define plausible scenario assumptions that account for cross-sector interactions. The development of these coordinated scenarios can often uncover coupled solutions across sectors, though must be carefully constrained to avoid unrealistic outcomes.

In decarbonizing regions, decarbonization pathways often form the foundation for downstream planning of natural gas and electricity system needs. Assumptions around energy efficiency improvements and electrification inform both infrastructure needs and strategies for managing major changes to energy demands across the economy.[4] The key outputs that flow into downstream analyses include:

- **Electrification demand and end-use adoption characteristics** (e.g., full home electrification vs. hybrid heat pump adoption, growing demand for electric light-duty, medium-duty, and heavy-duty vehicles), which inform infrastructure needs for generation, transmission, and distribution peaking

4 Energy efficiency here includes efficiency across many sectors of the economy, such as vehicle fuel economy standards, building shell improvements, industrial process efficiency, and many other efforts.

capacity as well as the design of related customer incentive programs

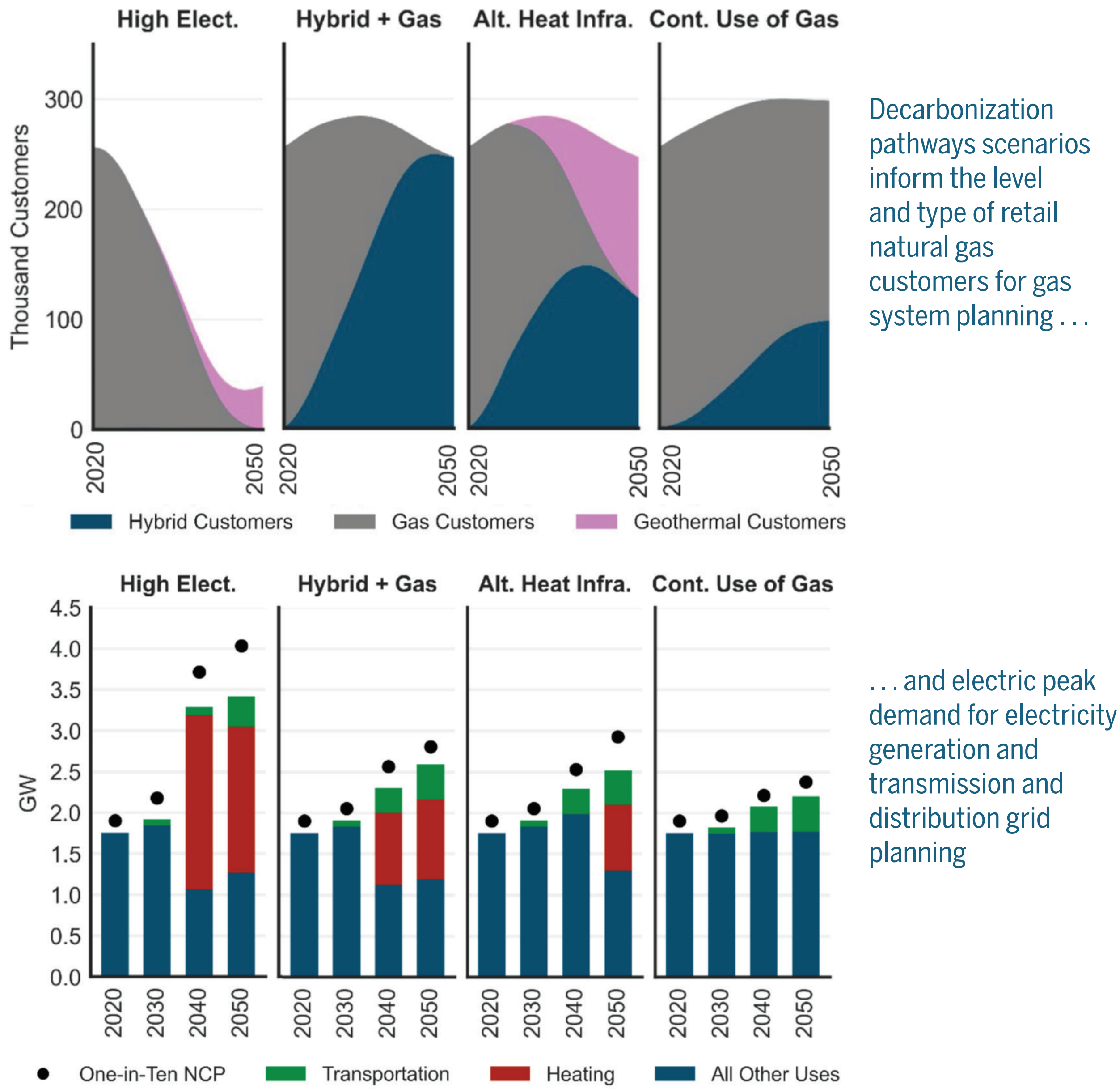
- **Needs for infrastructure for the production and delivery of clean fuels** (e.g., potential bioenergy, H2, or synthetic methane)
- **Declining throughput in delivery infrastructure for existing emitting fuels like natural gas** (such as local distribution pipelines), which will require strategies to manage the associated equity and affordability challenges of maintaining the high fixed costs of the natural gas delivery system as energy use shifts toward electricity and system throughput declines

With uncertainty in technology and the costs and feasibility of different decarbonization pathways, it is critical to consider multiple scenarios in downstream planning processes to assess the range of system needs and adaptive strategies considering these uncertainties. These downstream analyses can then inform future economy-wide decarbonization scenario planning by providing updated information on customer-side investment costs associated with electrification and/or energy efficiency, the relative customer rates for electricity versus natural gas usage, the feasibility and costs of meeting peak electrification demands, the costs of electricity for clean fuel production, and the cost and feasibility of clean fuels. Figure 7 (p. 16) shows forecasts of natural gas customers and peak electricity demand needs across different decarbonization scenarios in Rhode Island, highlighting how different scenarios can produce vastly different gas and electric infrastructure needs (Lintmeijer et al., 2024). For example, the "high electrification" scenario shows a large reduction in gas system customers and very high growth in peak electricity demand, both of which have major policy and planning impacts, while the "alternative heating infrastructure" scenario contains less growth in peak electricity demand facilitated by new networked geothermal heating customers.

In regions without decarbonization policy targets, there may not be a centralized analytical process with which to consider interactions between the energy demands of different economic sectors. However, there are still common foundational assumptions used to underpin the natural gas and electricity infrastructure planning that can be aligned across planning processes. Examples of these assumptions include long-term trends for economic development and population growth, rollover of the building stock and transportation fleets, and consideration of customer fuel-switching on future demands for natural gas and electricity.

FIGURE 7

Scenarios of Natural Gas Customers and Electricity Peak Demand Under Different Decarbonization Futures



This shows integrated scenarios of the evolution of natural gas system customers and load growth from electrification across decarbonized futures in Rhode Island. Four scenarios are shown: a high-electrification future whereby all existing natural gas customers adopt alternative heating technologies, a hybrid + gas scenario that includes hybrid heat pumps with natural gas back-up during extreme cold conditions, an alternative heating infrastructure scenario with expanded use of geothermal heating, and a scenario that forecasts the continued use of natural gas for heating. In the top panel, the natural gas customer forecasts include customers using traditional gas appliances, customers with hybrid heat pumps, and customers relying on networked geothermal heating. In the bottom panel, each bar in the electric peak demand graph represents the median coincident peak demand for the uses indicated, and the 1-in-10-year noncoincident peak demand for each scenario (indicated by the black dot). Heating electrification contributions to the peak indicate a transition to winter peaking.

Notes: NCP = noncoincident peak demand.

Source: N. Lintmeijer, T. Clark, S. Kinser, M. Bertolacini, K.enzie Schwartz, B. Wheatle, C. Li, D. Aas, and S. Smillie, "Rhode Island Investigation into the Future of the Regulated Gas Distribution Business. Technical Analysis Report. Docket 22-01-NATURAL GAS," Energy & Environmental Economics, Inc. (2024), https://www.ethree.com/wp-content/uploads/2024/06/Docket-22-01-NG-E3-Technical-Analysis-Report.pdf.

Electricity and Natural Gas Systems

The connections between natural gas infrastructure and electric power infrastructure have become increasingly important as reliance on natural gas–fired power plants has increased. The ability of natural gas production, storage, transmission, and distribution infrastructure to deliver gas when needed by the power system has become increasingly salient in regions reliant on natural gas power plants for resource adequacy needs. Electricity planners now understand that the ability of natural gas power plants to provide "firm" resource adequacy contributions relies on the ability of the natural gas system to reliably deliver firm fuel to those power plants. Additionally, the natural gas network—and in particular underground gas storage facilities—is also crucial to mitigating price volatility for electric power plants and thereby important for affordability for electricity customers.

Though there are national and sub-national differences in the level of planning and regulation, in the United States natural gas production is generally unregulated. Although natural gas transmission is regulated by the Federal Energy Regulatory Commission (FERC) on a pipeline-by-pipeline basis, there is no centralized planner for gas transmission akin to the transmission planning function within a regional transmission organization for electricity. For this reason, planners and operators are still determining the steps needed for coordinated planning and/or operations of natural gas production and transmission and the bulk electric power system. The local distribution of natural gas in the U.S., on the other hand, is generally regulated by state utility regulatory commissions and therefore subject to additional layers of regulated utility planning and cost recovery for incremental investments.

In decarbonizing systems there has emerged a new need to coordinate local planning for natural gas distribution systems and electrification of natural gas end uses. Locally targeted electrification, including associated customer programs and grid expansion, can be coordinated with retirements of existing natural gas distribution infrastructure to enable managed retirement of the existing gas system. Electrification can also be used as a "non-pipeline alternative" to gas system expansion, which can mitigate against stranded asset risks in decarbonizing regions. This strategy has the potential to manage the costs of future gas systems that may see lower utilization and help to ensure an appropriate balance of investment between electricity and natural gas infrastructure. Integrated planning methods can explore these strategies and support their implementation.

Integration of Planning Processes Within Electric Power Systems

Integrated planning within electric power systems has existed to varying degrees for decades: for instance, methods to link a generation portfolio to required transmission grid investments, integrated resource planning that considers both bulk grid as well as demand-side resource options, and the consideration of DER forecasts within distribution system planning assessments. However, these past practices are insufficient to meet the needs of planners today, who are rapidly facing an unprecedented wave of investments driven by load growth, policy goals, and technological advances.

Learning from Pioneers in Integrated System Planning

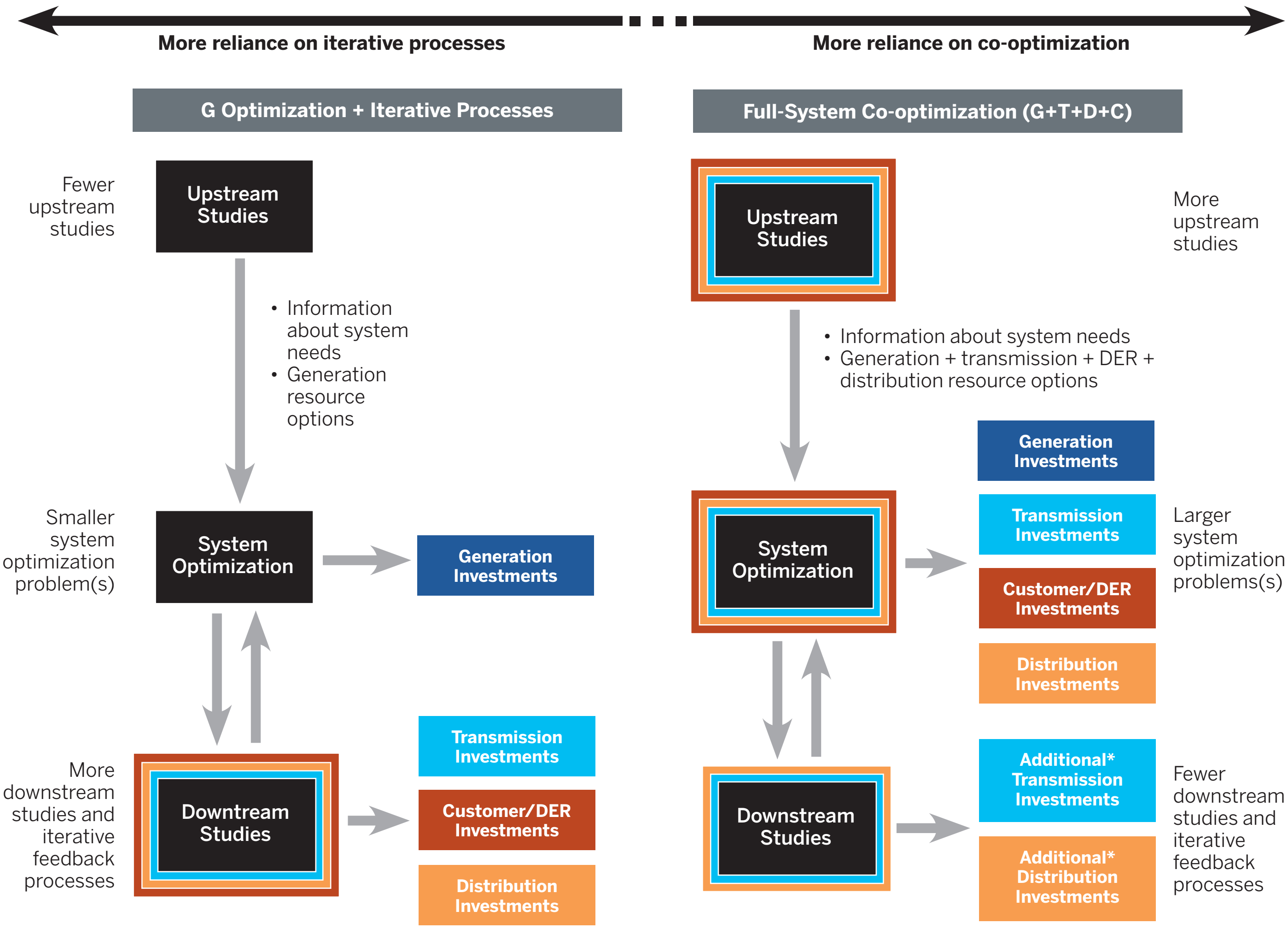
Planners today have the benefit of learning from early integrated electricity planning practices by industry pioneers, often referred to as integrated system planning (ISP), including ISP processes developed by Hawaiian Electric, Salt River Project, the Australian Energy Market Operator, the California Public Utilities Commission and California Independent System Operator, American Electric Power, Duke Energy, Réseau de Transport d'Électricité (RTE), the European Network of Transmission System Operators for Electricity (ENTSO-E), and others. While all integrated electricity planning processes need to focus on establishing the data and model linkages between generation, transmission, distribution, and customer program and DER planning domains, each process will be distinct due to the unique organizational realities, modeling processes, business strategies, and regulatory models facing each power system.

The Importance of Information Flows Between Planning Domains

The key for any integrated electricity planning process is for information to flow between the analyses used to

FIGURE 8

Integrated Planning Methods Based on Either Iteration or Full System Capacity Expansion Optimization



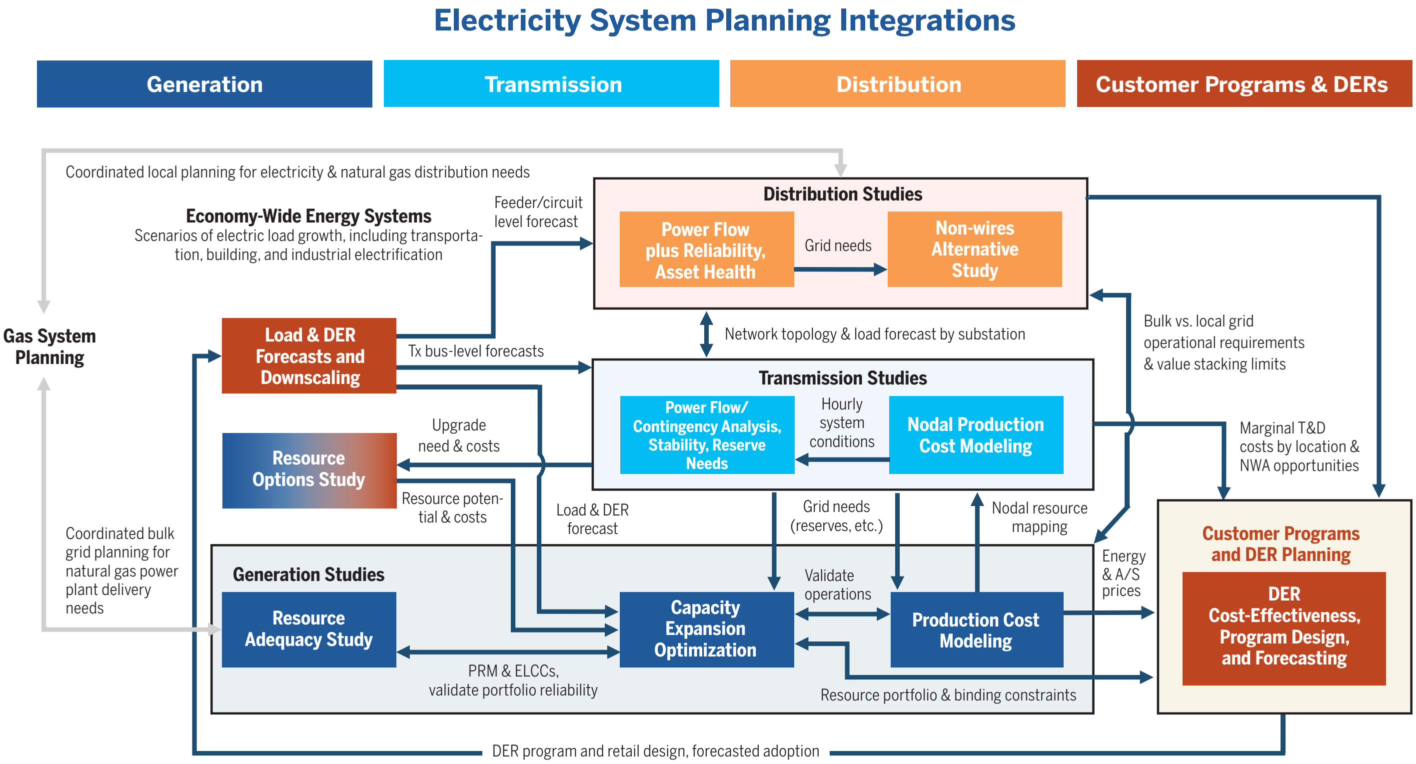
A spectrum of integrated planning designs from a greater reliance on iterative processes to a greater reliance on co-optimization methods. Boxes indicate the planning domains incorporated in each stage (dark blue = generation, light blue = transmission, orange = distribution, dark orange = customer programs/DERs). White arrows show a relative increase or decrease in scope of the upstream/optimization/downstream studies.

* Note that the full set of trnasmission and distribution grid investments will need to be determined through more detailed and/or granular set of analyses (power flow, stability, protection, etc.) than can tractably fit into a system capacity expansion optimization.

Source: Energy Systems Integration Group.

assess infrastructure needs in each planning domain. Exactly how the information flows will vary. Some processes will use expansions of individual models (such as capacity expansion optimization) to endogenously capture those information flows within a co-optimization across planning domains, such as co-optimization expansion of generation, storage, and transmission. Other processes will use exogenous information transfers to use outputs from one model as inputs to the next, developing integrated planning scenarios. Some processes will be iterative, developing initial inputs into another model that are then further refined as multiple modeling processes are run to convergence. Planning done by entities located within wholesale energy markets may require additional inputs for assumptions of future energy, ancillary service, and capacity market prices. Figure 8 shows a schematic for the relative size of upstream studies, optimization problems, downstream studies, and level

FIGURE 9
Integrated Electricity System Planning Data Flows



Notes: A/S = ancillary service; DER = distributed energy resource; ELCC = effective load-carrying capability; NWA = non-wires alternative; PRM = planning reserve margin; Tx = transmission; T&D = transmission and distribution

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

of iteration between a predominantly iterative approach and an approach based on full system capacity expansion optimization. Multiple options exist on the spectrum between these two.

Figure 9 shows a flow chart of key information flows between the four G/T/D/C electricity planning domains. The chart highlights the information flows that are necessary to substantiate a comprehensive electricity planning process. Natural gas system planning and economy-wide energy systems are shown for reference, recognizing that not all integrated electricity planning processes will include those integrations.

Table 4 (p. 20) explains the function of each process in Figure 9 as well as the key information that flows from each planning domain to other planning domains.

TABLE 4

Connections Between Electricity System Analytical Processes in an Integrated Planning Process

Generation Planning	Transmission Planning

- **Resource options study** incorporates transmission upgrade options for deliverability or congestion relief as informed by detailed transmission studies.
- **Resource adequacy study** determines reliability need and resource counting, validates portfolio reliability from a capacity expansion model, and may incorporate multi-zone or more detailed transmission topology.
- **Capacity expansion optimization** selects candidate generation, storage, and transmission options to meet reliability and policy constraints at least cost, using inputs from resource options and resource adequacy studies.
- **Production cost modeling** validates operability and flexibility needs of a capacity expansion portfolio using hourly load and resource dispatch modeling. Includes ancillary service needs developed from detailed transmission grid simulations. May be zonal or nodal. Nodal production cost modeling uses granular bus-level loads and resources to model hourly transmission security-constrained economic dispatch using DC power flow, identifying transmission congestion and snapshot dispatch conditions for AC power flow modeling. May include contingency analysis.
- **Busbar mapping** of generation and storage resources produces more granular resource locational assumptions (as needed) for nodal studies.
- **AC power flow and contingency analysis** uses detailed AC representation of grid power flow to identify thermal overloading and voltage violations, typically based on snapshot conditions from DC power flow (that may require iteration with nodal production cost model), run under normal and contingency conditions (N-0, N-1, N-1-1, etc.).
- **Grid stability modeling** considers dynamic response to disturbances to ensure transmission reliability (frequency, voltage, etc.). May feed back dispatch constraints, needs for existing ancillary services, or new ancillary service needs to upstream production cost models or mitigation investment needs to capacity expansion models.
- **Analyses of ancillary service needs** determine amounts of various existing and new operating reserve products needed. These needs may vary dynamically based on time of day and season and may feed back to upstream production cost models as various reserve requirements and to capacity expansion models as requirements for specific resource characteristics. Additional transmission analysis may be needed to ensure deliverability of reserves.
- **Asset health analyses** consider asset replacement needs for age or other reasons, coordinated with new capacity needs to co-optimize repair/maintenance and grid expansion needs (reconductoring, etc.).

Generation Planning	Customer Program and DER Planning

- **Load forecasts** form the basis for power system needs; they are typically developed using econometric methods and can be supplemented by **economy-wide energy system studies** (including **decarbonization scenarios**) for electrification assumptions.
- **DER forecasts** are produced using utility and customer cost-effectiveness studies and customer adoption models. Forecasts include assumptions for output shapes and operational capabilities or price responsiveness for dispatchable DERs; adoption scenarios may inform capacity expansion scenarios (high vs. low energy efficiency, etc.).
- **Load and DER downscaling** produces the appropriate granularity of forecasts to match capacity expansion and production cost model topology.
- **Resource options study** may consider DERs as candidate resources, detailing their potential, costs, and operational capabilities for input into capacity expansion optimization.
- **Capacity expansion optimization** uses load/DER forecasts and/or may select DERs optimally. It also produces resource portfolios and binding policy constraints (greenhouse gas emissions, renewable portfolio standards, etc.) from which **avoided costs** can be derived for cost-effectiveness analysis and utility rate design.
- **DER cost-effectiveness studies** consider utility and/or customer costs and avoided costs under multiple viewpoints (known as "cost tests") and support **DER program design** and **customer adoption modeling** for DER forecasts.
- **The dispatch of distribution-connected resources** should be aligned between bulk system economic modeling (per these resources' bulk grid benefits), distribution system modeling (per their distribution system benefits), and the price signals customers see through retail rates and/or customer program incentives.

(CONTINUED)

TABLE 4

Connections Between Electricity System Analytical Processes in an Integrated Planning Process (CONTINUED)

Distribution Planning	Customer Program and DER Planning

- **Distribution studies** for each distribution circuit that identify **grid needs** can be used to develop marginal costs for distribution investments to value **avoided costs for distribution** (which may be locationally distinct) and can explore **grid modernization** investments and operations (distributed energy resources management systems (DERMS), DER control/communications, etc.). These studies include:
  - **Power flow studies** that ensure that thermal constraints, voltage limits, and power quality requirements are not violated.
  - **Short-circuit studies** that assess the ability of circuit breakers to break current under various high-current fault conditions.
  - **Stability studies** that test the ability of a grid to dynamically respond to key disturbances.
  - **Protection studies** that assess the ability of relays, switches, and other protection equipment to operate upon a grid disturbance.
  - **Asset health analyses** that determine investment needs to maintain or replace aging assets.
- **Non-wires alternative studies** identify opportunities where DERs can provide distribution service equivalent to traditional "wires" investments and support sourcing of those solutions via utility build, competitive solicitations, programs, or tariffs. There may also be proactive opportunities to site DERs in locations with expected future load growth prior to triggering a grid upgrade need; an example would be creating more flexibility to accommodate expected electrification demand.

Transmission Planning	Customer Program and DER Planning

- **Load and DER downscaling** produces transmission bus–level load and DER forecasts for transmission studies.
- **Transmission studies** produce marginal costs for transmission investments that can be used to value avoided costs for transmission, which may be locationally distinct. These studies should include forecasted DERs and consider any transmission operational changes needed to accommodate DERs, including the combination of inverter-based resources on both the bulk and local grids, backflows from distribution to transmission, etc.

Transmission Planning	Distribution Planning

- **Transmission-level AC power flow models** can be integrated with **distribution-level power flow models** to align modeled conditions (voltage, etc.) at the transmission-distribution interface. Network topology and load forecasts should also be aligned between transmission and distribution studies.
- **Resource siting and coordinated transmission/distribution planning** can consider the relative costs and benefits of distribution system upgrades versus transmission system upgrades. At times, distribution solutions (e.g., feeder voltage management) may be more economical than transmission-level solutions (e.g., a new substation). In addition to costs, the relative timeline for a distribution versus transmission solution can inform decision-making.

Generation Planning	Distribution Planning

- DER resources located on distribution grids can value-stack bulk grid benefits and local grid benefits including distribution deferral. In many cases, this may make additional DER investments cost-effective. However, there needs to be an analysis of the **operational requirements to provide bulk grid and local grid benefits** and any **limitations that may impose on value stacking potential** (e.g., resource adequacy capacity versus local grid deferral for use-limited resources like distributed storage).

Key analytical processes and their interactions across planning domains.

Source: Energy Systems Integration Group.

Integration of Actions

The alignment of inputs/scenarios and analytical processes as described above is crucial to create an integrated system plan that meets planning constraints across generation, transmission, distribution, and customer programs and DERs in a holistic manner. An integrated system plan will document those inputs, analytical processes, and the near- and long-term plans for each system component that result. An additional key outcome—arguably the most important—is a **near-term action plan** describing the specific investments that will be made as an outcome of an integrated planning cycle.

As shown in Figure 10 (p. 23), the action plan describes the traditional types of investments in each domain as well as the novel types of investments that have resulted from integrated planning, such as DER sourcing for generation or grid needs and targeted siting of storage to meet locational grid needs. For a vertically integrated utility performing an integrated planning process on its own system, an action plan may be a single document describing investments across all domains. In other cases, multiple action plans may be produced, such as for a vertically integrated utility that may require investment approval from multiple regulatory bodies or for a multi-organization integrated planning process, and these should be tightly coordinated to ensure consistency with the comprehensive planning solution identified. This coordination can be a challenge, given multiple decision-makers and/or misaligned timelines; these challenges are discussed further in the next section, "Integration into Decision-Making."

Generation Investments

A generation investment plan should describe the generation and storage resources needed to meet system reliability and policy obligations in an affordable manner.

Arguably the most important outcome is a near-term action plan describing the specific investments that will be made as an outcome of an integrated planning cycle.

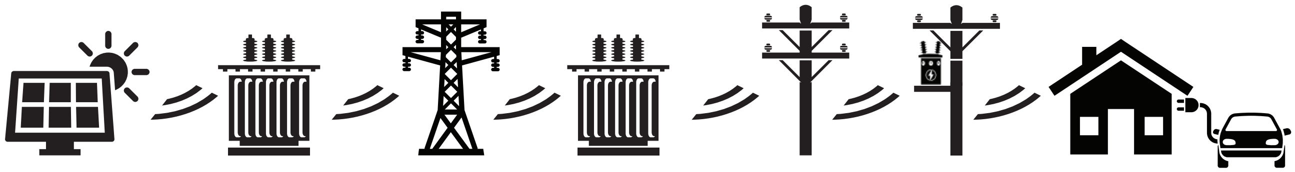
Generation solutions may be developed by a regulated utility or procured through competitive solicitations. Needs can be specified as specific resource types or can be translated into technology-neutral resource attributes and/or resource locations. The latter allows for greater flexibility during the competitive procurement process to adapt the final resources procured to market conditions, allowing third-party bids that differ from assumptions developed a year or two earlier at the beginning of the planning process. Constraints resulting from stability analysis and ancillary service needs assessment may be incorporated into generation investment plans in the form of specific resource types, resource attributes, and/or resource locations.

Transmission and Distribution Investments

A transmission investment plan and a distribution investment plan should consider the traditional wires investments needed, other grid upgrades or grid modernization equipment, as well as more novel types of "non-wires alternatives." Traditional wires investments broadly include new lines, substations, transformers, capacitor banks, and protection equipment. Other grid upgrades and grid modernization equipment include synchronous condensers, STATCOMs, series line compensation, advanced conductors, dynamic line rating strategies and measurement devices, and distributed

FIGURE 10

Components of an Action Plan Resulting from an Integrated Planning Process



Generation | Transmission | Distribution | Customer Programs & DERs

Action plans are consistent with integrated planning and require coordination across teams

Generation resource action plan

- Recource investments and/or procurement need
- All-source request for proposals
- Requests for proposals targeted by location

Transmission action plan

- Transmission asset investments
- Storage providing transmission service
- Regional transmission project participation

Distribution action plan

- Investments in substation/ lines/grid modernization
- Development of targeted DER/customer programs
- Non-wires alternatives solicitations

Customer/DER programs and rates action plan

- Customer program evaluation and design for efficieincy and equity
- Rate design updates

Plus pilot programs to validate planning assumptions (technology pilots, commercial pilots, operational pilots, etc.)

Near-term action plan components across proposed investment categories and pilot program recommendations.

Source: Energy Systems Integration Group, adapted from A. Olson, J. Hooker, A. Burdick, and L. Alagappan, "Integrated System Planning: From Vision to Reality," Energy and Environmental Economics, Inc., ISP Webinar Series presented September 26, 2024.

energy resource management systems (DERMS). Non-wires alternatives generally consist of investments traditionally considered in other planning domains, such as targeted siting of generating resources, energy storage, customer-sited DERs, and DER pricing or operational control programs that can provide grid operators the necessary capabilities to offset traditional grid investments. Like the flexibility that a competitive generation procurement process can achieve, procurement processes for non-wires alternatives ideally enable the option to use the wires investment in the case that the non-wires option is deemed not cost-effective or otherwise infeasible. Grid investments can be coordinated or directly co-optimized with investment plans for generator additions and DER activities to ensure sufficient investments for reliability, stability, and other grid needs. This coordination is increasingly important as investments across planning domains can provide multiple value streams.

Customer Programs and DER Investments

A customer program and DER investment plan consists of the levels of DERs targeted and the associated sourcing mechanisms to achieve those levels. Customer resources can be sourced through multiple mechanisms. Competitive procurement processes, including "all source" solicitations, can consider DERs as resource options that directly compete with bulk grid resources or grid investments. Customer program design requires consideration of targeted incentives to support DER adoption, the marketing and education programs necessary to inform customers and facilitate technology adoption, and the measurement and verification processes needed to ensure that incentive payments are effective and minimize free ridership. Lastly, DERs can be incentivized through retail rate design and specialized tariffs—for example, net metering or net billing tariffs.

Demand charges and time-of-use rates can also incentivize customers to adopt new technologies or to change their behavior in beneficial ways. Retail rate design, which has historically been considered a separate process that follows planning, needs to be better integrated with planning to influence customer behavior in a manner that aligns with the optimal integrated system plan. Careful consideration must be given to changes to rate designs or program offerings that have caused customers to invest in DERs, balancing flexibility for those mechanisms to reflect evolving grid value while providing enough certainty to drive customer investments.

Pilot Programs to Validate Planning Assumptions and Explore Novel Use Cases

Since an integrated planning process will often consider new technologies or new applications of technology beyond their historical purpose, an integrated planning action plan may also include pilot programs to test and validate planning assumptions or further explore these novel use cases. Technology or operational pilots consider the use of emerging or novel technologies or operational methods that can support planning needs. Examples include advanced transmission technologies, multiple-use applications for energy storage such as dual wholesale/retail market participation, and DER operational control schemes. Sourcing pilots can be used to validate novel ways to source planning needs. For most planners, sourcing non-wires alternatives is a promising but new way to address grid planning needs. Pilots can explore the timing, performance requirements, and product pricing methods that are needed to effectively source non-wires alternatives. For instance, different commercial terms in a non-wires alternative solicitation will have different impact on bid prices and therefore project viability relative to the traditional wires upgrade.

An integrated planning action plan may include pilot programs to test and validate planning assumptions or further explore novel use cases for transmission, storage, and other technologies.

Pilots will unlock new information that can be incorporated into future planning processes. In some cases, pilots may reveal that solutions assumed during planning are not viable, requiring adjustments to the solutions studied in the next integrated system plan. In other cases, they will produce better data on resource capabilities or costs that can enable planners to rely on novel solutions and/or value stacking with great confidence in future planning cycles.

Integration of Planning with Decision-Making

Planners face an extremely wide variety of regulatory models under which integrated planning may occur. Integrated planning for an isolated island grid like Hawaii has a unique planning and regulatory environment where a single vertically integrated utility may perform all planning functions internally in a way that facilitates model alignment, data transfer, and the development and application of strategic objectives. In contrast, a regional wholesale energy market may have a FERC-regulated transmission planning organization, many state-regulated distribution utilities, no long-term generation planner within the deregulated market, and a combination of local utilities and state governments planning customer and DER programs. Many places may be in between those two extremes, such as a generation and transmission provider that must coordinate with many local distribution utilities or cooperatives. In general, the more organizations involved in planning the power system, the more complicated and potentially challenging it can be to create an integrated planning process. However, there are examples of multi-organization coordination on integrated planning, such as the integrated generation planning, transmission planning, and DER valuation and forecasting process undertaken by the California Public Utilities Commission, the California Energy Commission, and the California Independent System Operator.[5]

5 https://www.cpuc.ca.gov/irp/; https://www.cpuc.ca.gov/dercosteffectiveness; https://www.caiso.com/generation-transmission/transmission/transmission-planning.

No matter the regulatory model, an integrated planning process must be designed to function within the set of decision-making processes that will ultimately approve the planned infrastructure investments. The following sections outline the key questions that planners can ask themselves to design an integrated planning process that will function within their decision-making context.

What are the key planning objectives?

To effectively design a successful integrated planning process, planners and decision-makers should be aligned on the key planning objectives. These will often center on the foundations of electricity planning: safety, reliability, and affordability. However, other or additional objectives may be a priority in certain jurisdictions, such as sustainability, economic development, or technology or market transformation.

What are the key decisions to be made?

The front-end design of an integrated planning process starts with determining what decisions must be made at the back end. What infrastructure investments will be determined by planning? What timeline of investments will be made in this cycle? Are policies only an input into the planning process or can the planning process inform policy changes? Aligning on the specific decisions to be made will enable alignment on the key objectives for the entire process. There will also be many decisions made during the planning process itself, including the key planning objectives, analytical design, scenarios, and input assumptions.

Who are the stakeholders and how will they be engaged?

Stakeholder engagement is critical to every planning process. Stakeholders, including customer advocates, environmental organizations, and technology vendors, are seeking increased access to and understanding of how decisions are made in electricity system planning. They seek to provide another layer of oversight to ensure planners approach the process in a robust and fair manner. Planning typically involves the coordination of internal stakeholders (e.g., within a utility), external stakeholders (e.g., advocates), and regulators, each with varying degrees of access to information, varying levels of technical understanding, and varying resource needs to engage in detailed review of the process. Integrated planning across multiple organizations involves an additional layer of cross-organizational engagement. Therefore, all integrated planning processes need to have a robust stakeholder engagement plan. This plan would consider one or multiple venues for planners to share information with stakeholders, with the goal of ensuring participation and transparency into the planning processes, methods, assumptions, and results.

Who is the decision-maker for proposed investments?

Ultimately, there must be a decision-maker or deciding organization for each infrastructure investment proposed. In some cases, there may be multiple decision-makers within or across organizations. For instance, planning for new offshore wind generation may require key decisions from utility leadership, approval for cost recovery of generation costs from state utility regulators, and approval for transmission cost recovery from a federal regulator. When designing a planning process, it should be clear who will ultimately make the final decision for each infrastructure investment proposed in the action plan, and the process should be designed to give those decision-makers access to the information needed to robustly and confidently make the decisions. Additionally, processes are needed to determine who will decide key inputs and design parameters during the planning process itself (input assumptions, scenario design, resource adequacy targets, etc.). When multiple organizations are involved in planning and/or decision-making, it is critical to establish a robust coordination process to securely share data, iterate between organizations, and coordinate decision-making.

When will decisions be made?

Some decisions will occur during the planning process itself, while other decisions will occur during regulatory approval of a proposed action plan that results from the planning process. Still others will be made outside the planning process itself, such as during a competitive procurement solicitation process. Planners engaged in planning processes with multiple organizations or multiple regulators will often find themselves facing different timelines for decisions on different types of

investments proposed in an integrated plan. This can create a challenge, since the need for one investment may be dependent upon the decision made on another investment (e.g., the decision on approving a customer DER–based non-wires alternative will determine whether the traditional distribution wires investment is needed). The planning process should be designed around these challenges, including aligning the timing of when each proposed investment will be approved for investments with key dependencies but different decision-makers. This alignment of planning processes may initially create delays compared to current timelines, but it will ultimately produce a more robust and stable process. It may be necessary to align not just final decision-making timelines, but also stakeholder and decision-maker review of inputs and methodologies along the way.

How can planners ensure that decisions are both adaptive and robust?

All planners face a wide range of uncertainty in the inputs and scenarios that drive investment needs. Integrated planning may create new additional types of uncertainty related to the ability to source and implement value-stacked solutions that can lead to lower total system costs. *Adaptive* planning incorporates the consideration of uncertainty into the timing of investment decisions. Some decisions must be made in a given planning cycle while others can be delayed until future cycles. When feasible, delaying decisions allows planners to adapt to future changes in system needs, technology, or market conditions. This optionality provides planners with a key tool to manage uncertainty and minimize the risk of stranded or sub-optimal asset investments.

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Robust planning involves broad consideration of uncertainty for decisions when they must be made. It is particularly critical for large, long-lead-time assets like new transmission lines or offshore wind resources, which are lumpy investment decisions needed for extended project development processes to begin. The need for robust planning is driven by the level of consequence of an investment (such as its costs), the degree of uncertainty, and the time for implementation. While investments with high uncertainty and large consequences benefit from a robust planning approach, investments with lower consequences and more timeline flexibility, including customer programs and smaller local distribution system upgrades, benefit instead from an adaptive planning approach. Tools like scenario or sensitivity analysis, stochastic optimization, robust optimization, and additional methods considered in the field of “decision-making under uncertainty” such as least-regrets planning are all approaches to ensure robust planning and investment decision-making processes.

Key Steps Toward Integrated Planning

This report provides a foundational framework for integrated planning from which planners can begin their journey toward greater levels of integration. The move to integrated planning can be viewed as a change management or process improvement exercise. Within that context, it is paramount to first assess the starting point of a planning process. Once planners answer the questions of what are the key objectives, where are the known and potential places for misalignment, and which of those are most impactful for near-term decision-making, then they face a choice. They could try to tackle the change management needed to reach a fully integrated planning process immediately. However, it is often preferable to make incremental changes to existing processes and organizational structures that can be built upon in successive cycles. This type of walk/jog/run approach forms the basis for ESIG's *Integrated Planning Guidebook*, with its specific recommendations for planners in each domain and for leaders who manage planners across domains to move iteratively toward a more integrated planning process.

A generalized set of steps is suggested below, although the exact order will be different for each planning process.

- Determine integrated planning objectives
- Perform a gap assessment for existing planning processes
- Align key inputs and develop integrated scenarios
- Develop deeper connections between existing analytical processes
- Create or adapt stakeholder engagement plans to support an integrated planning process
- Consider organizational re-alignment and/or formalized agreements between planning organizations
- Advance new analytical methods and tools to facilitate planning integrations
- Consider new opportunities for co-optimization or co-simulation methods across planning domains

Technology and policy drivers are pushing planners toward a more integrated approach. The framework presented in this report forms a foundation upon which planners can build to reap the benefits of new comprehensive planning methods. While each integrated planning process presents its unique opportunities and challenges, all processes can improve by strengthening their technical and procedural connections across planning domains.

Foundations of Integrated Planning: Defining a Framework for Comprehensive Energy System Planning

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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