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January 14, 2021

VIA ELECTRONIC FILING

Ms. Kimberley A. Campbell
Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4300

RE: Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's September 2020 Smart Electric Power Alliance Report
Docket No. E-100, Sub 165

Dear Ms. Campbell:

Pursuant to the Commission's January 12, 2021 *Order Scheduling Technical Conference and Requiring Filing of Report*, I write on behalf of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC and enclose the September 2020 Smart Electric Power Alliance report, "Integrated Distribution Planning: A Framework for the Future," for filing in connection with the referenced matter.

Thank you for your attention to this matter. If you have any questions, please let me know.

Sincerely,

Lawrence B. Somers

Enclosure

cc: Parties of record

CERTIFICATE OF SERVICE

I certify that Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's September 2020 Smart Electric Power Alliance Report, in Docket No. E-100, Sub 165, has been served by electronic mail, hand delivery or by depositing a copy in the United States mail, postage prepaid to the following parties of record

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This the 14th day of January, 2021.

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Smart Electric Power Alliance

Integrated Distribution Planning: A Framework for the Future

September 2020

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About SEPA

The Smart Electric Power Alliance (SEPA) is dedicated to helping electric power stakeholders address the most pressing issues they encounter as they pursue the transition to a clean and modern electric future and a carbon-free energy system by 2050. We are a trusted partner providing education, research, standards, and collaboration to help utilities, electric customers, and other industry players across four pathways: Transportation Electrification, Grid Integration, Regulatory Innovation and Utility Business Models. Through educational activities, working groups, peer-to-peer engagements and custom projects, SEPA convenes interested parties to facilitate information exchange and knowledge transfer to offer the highest value for our members and partner organizations. For more information, visit www.sepapower.org

Disclaimer

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1 The information in the report was informed by but does not explicitly represent the views or endorsement of the reviewers and participants.

Executive Summary

For decades, traditional distribution planning practices have helped utilities meet core requirements for providing safe, reliable and affordable delivery of electricity. However, advancements in technologies, trends in customer distributed energy resource (DER) adoption, and expanding clean energy goals are prompting reevaluation of current distribution planning practices. These developments point to an increasingly complex distribution grid, and bring electric and technical considerations to light when considering the traditional distribution grid's capabilities and planning processes. Utilities will face multiple challenges with regards to visibility, tools, and resources (e.g., skilled staff, investments) needed to manage a growing number of DERs. The desire to get out in front of these challenges has been a key driver for utilities investigating integrated distribution planning (IDP) today.

SEPA explores IDP in this report from a holistic perspective centered around two key traits:

1. Integration of internal elements and processes within the utility to enhance distribution planning, and
2. Integration of distribution planning with transmission and generation planning (as it applies).

This paper examines IDP predominantly through a distribution lens. This includes evaluating how distribution planning processes may need to become more integrated internally (i.e., bring together separate planning processes, as well as planning and operations groups) and discussing integration between transmission, distribution, and generation (TDG) planning from a distribution perspective (i.e., examining how distribution can become more coordinated and integrated with transmission and generation planning).

In response to growing interest from utilities, regulators, and other stakeholders looking to unpack the complexities behind IDP, SEPA distills IDP into a framework that lays out an incremental, phased approach to transitioning from traditional to integrated distribution planning.

Key Report Takeaways

The term IDP, in this paper, refers to the broad spectrum of efforts utilities and stakeholders are undertaking to advance distribution planning processes. Key points underlying these frameworks and addressed in the report include:

- **Context and a utility's starting point are key in IDP:** As utilities begin to investigate IDP, they need to understand the goals and factors driving changes in their region, the capabilities of their existing distribution system, and the potential challenges or limitations they can anticipate. A utility's starting point is determined by: the vision, objectives, and goals at the utility or within its jurisdiction; anticipated DER adoption in the service territory; existing tools, resources, and available technology; existing or planned distribution infrastructure investments; and other considerations such as resilience and future threats along the system.
- **IDP consists of six key elements** grouped into two classifications. 1) ***Core IDP Elements*** (i.e., central to any IDP process) which include forecasting, sourcing solutions for grid needs, and TDG integration, and 2) ***Additional IDP Elements*** (i.e., with varying priorities depending on objectives, goals, and other circumstances unique to each utility) which include interconnection data integration, hosting capacity analysis, and stakeholder engagement.
- **Elements included in each utility's IDP may vary:** The core and additional elements included in a utility's IDP process may vary in importance depending on the vision, goals, and objectives. Regulatory constructs and grid limitations all provide context and influence the starting point and end state for IDP.
- **Incremental advancement can occur within a four-phase maturity framework.** However, it is important to note the following:
    - ***Progress may vary by element:*** Utilities may exist in different phases across elements (e.g., Phase 2 Forecasting and Phase 1 Hosting Capacity). This framework does not imply that a utility must operate at the same phase across all IDP elements.
    - ***Phase 4 may not be an appropriate end state:*** Phase 4 detailed across IDP elements points to an aspirational future state to guide the progression of IDP. SEPA cautions against expectations that all utilities progress to Phase 4, and emphasizes thoughtful consideration of the goals utilities and their stakeholders are trying to meet.

ES-1: Phased Integrated Distribution Planning Framework

		Phase 1	Phase 2	Phase 3	Phase 4
Core IDP Elements	Forecasting	Load forecasting with limited visibility	Load forecasting with standard visibility	Load forecasting with increased visibility	Advanced, integrated granular forecasting
Core IDP Elements	Sourcing Solutions for Grid Needs	DERS not considered to address distribution system needs	Piloting DERs and non-traditional solutions	Evaluation of DERs and non-traditional solutions integrated in IDP process	Streamlined DER solutions sourcing based on locational and temporal value
Core IDP Elements	Transmission/ Distribution/ Generation Integration	Siloed planning processes	Annual, iterative approach	Increasingly iterative approach	Continuous, co-optimized planning processes
Additional IDP Elements	Interconnection	Manual process	Increasingly digitized and streamlined process	Increasingly automated and streamlined process; coordinated with other IDP processes	Fully integrated process with other IDP elements
Additional IDP Elements	Hosting Capacity	Limited, manual analysis	Basic functionality static analysis	Increasingly complex, iterative, and/or coordinated analysis	Fully integrated, continuous analysis with other IDP elements
Additional IDP Elements	Stakeholder Engagement	Limited, internally driven	Informative outreach	Proactive engagement	Incorporated
	IDP Coordination & Integration	Less coordinated or integrated			Fully integrated

Source: Smart Electric Power Alliance, 2020.

- **Key challenges at each phase:** Advancing through phases will encompass a number of considerations (e.g., technology implementation, organizational capability, regulatory context) and challenges, as detailed in the report (see Key Considerations).
- **Integration of distribution planning:** As utilities look to transition into later phases of IDP, the integration of distribution planning may happen along multiple dimensions, including: 1) among different elements of IDP, 2) among distribution, generation, and transmission, and 3) among asset planning, system expansion, and grid modernization.

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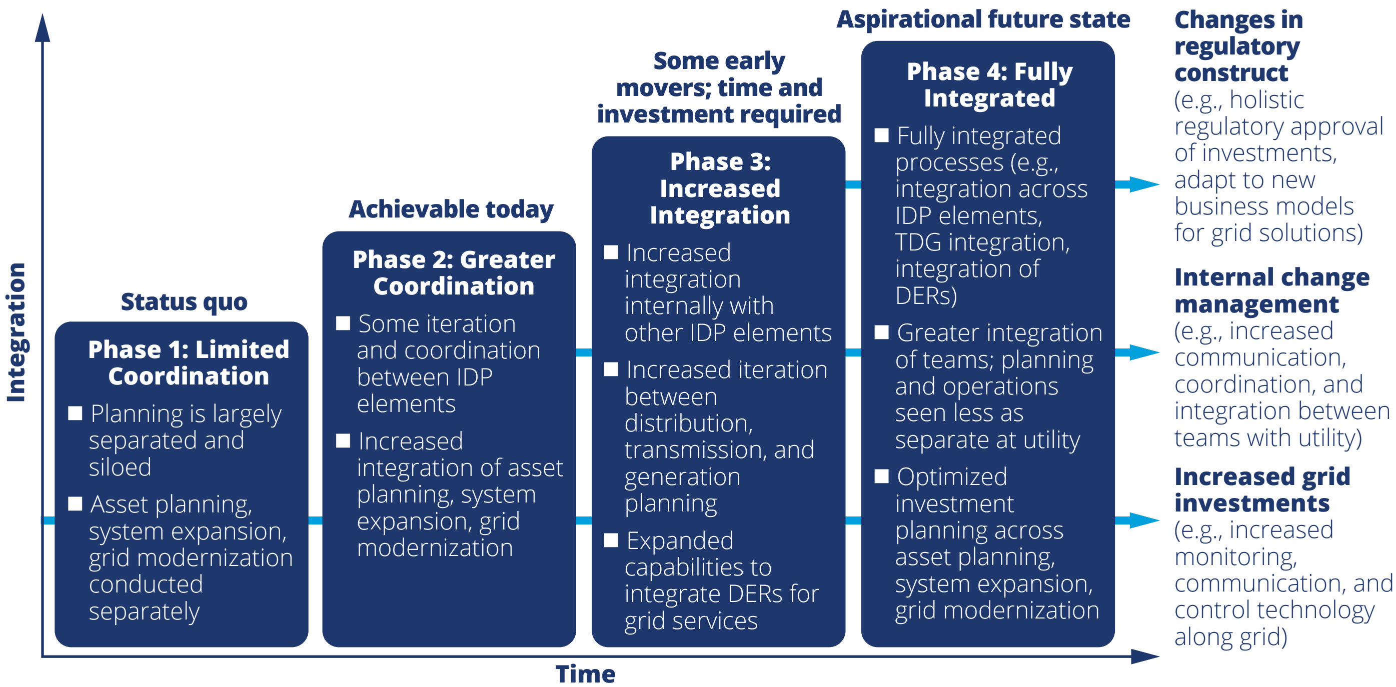
ES-2: Phased Progression and Requirements for Integration in IDP



Source: Smart Electric Power Alliance, 2020.

Key Considerations

Advancing towards IDP will require tackling a number of challenges and obstacles. Overcoming a few key challenges will be necessary to help advance IDP, including:

- **Bridging existing technology gaps and investing in foundational grid improvements for future planning:** Current tools and capabilities prevent distribution planners and operators from seeing customers' DER performance and output. There is a need to continue investing in the distribution grid and developing advanced planning and operational tools to provide greater grid visibility and control, and to better integrate DERs into grid planning and grid operations.
- **Investing and building competencies in big data at utilities:** The complexity of collecting, managing, and analyzing increasingly granular data will grow as utilities advance towards later phases of IDP. This will require investment in people (e.g., staff training, talent acquisition), tools (e.g., cloud operations for data storage), and standardized analytics to enable advanced data analytics and ensure data quality, security, and accuracy.
- **Change management and integration of systems, groups, processes:** As utilities transition from traditional distribution planning to IDP, a considerable amount of time and effort will be required to integrate disparate systems, tools, and groups. In some cases, the systems and tools needed to enable integration may not yet exist. This will be even more so the case when coordinating across distribution, transmission, and generation planning. Utility staff will also need increased training and talent acquisition to navigate an increasingly technically complex distribution grid.
- **New regulatory constructs:** The ability for utilities to advance to more mature phases of IDP may be limited by existing regulatory constructs. These regulatory constructs likely need to evolve to enable IDP, as well as to create opportunities for new business models for grid solutions.

Introduction

Given the multitude of changes facing utility companies, including efforts to transition to a clean and modern energy system, a growing number of regulators and utilities are beginning to rethink traditional distribution planning processes. Regulators and policymakers are starting to push new processes, coined "integrated distribution planning" (IDP). Inherent in all IDP processes are the needs to further integrate planning processes and increase transparency into an internal utility process. The efforts may vary in approach and goals, but often focus on the integration of distributed energy resources[2] (DERs) and other non-traditional solutions (e.g., non-wires alternatives).

The energy industry has long discussed the challenges and opportunities presented by integrating significant amounts of DERs into the grid. Recent trends indicate the possibility that significant, system-wide DER adoption may be closer than expected. Wood Mackenzie recently projected that DER capacity will reach 397 gigawatts by 2025.[3] Additionally, The Brattle Group estimates the number of electric vehicles on the road will grow from 1.5 million in 2020 to 10-35 million by 2030.[4] Adoption of new technologies at this scale will bring an unprecedented level of complexity to the grid. Grid planners will need to anticipate and plan for fluctuations in supply and demand of energy along the grid, resulting from a large number of DERs and changing customer behaviors. Future planning efforts will require changes to and greater integration of processes, and significant investment in infrastructure, tools and people.

As utilities and regulators react to these trends, they agree that traditional distribution planning will evolve. Importantly, the pace and scale of this evolution will vary depending on each utility's circumstances. This evolution is complex and nuanced, and becomes increasingly challenging when considering the differences in jurisdictions, regulatory environments, types of utilities (i.e., investor-owned, public power, cooperative), size of service territory, and DER adoption levels, to name a few. This report focuses on how the distribution planning process may evolve, and is applicable across different utility types.

Understanding that the transition towards integrated distribution planning, and the future state for a utility, is highly dependent on the unique goals, needs, and circumstances at each utility, SEPA outlines a maturity model framework for transitioning from traditional distribution planning to more integrated distribution planning. This framework deconstructs the IDP process into key elements, and identifies, from a practitioner's perspective, the key considerations and challenges the industry will need to address.The insights discussed in this paper are based on interviews with utilities and industry experts, as well as a review of existing industry research and regulatory activity in the distribution planning space.

This paper aspires to answer a few key questions:

- What is integrated distribution planning and how is it different from traditional distribution planning?
- What is driving IDP?
- What resources exist to help utilities and their regulators evaluate the efficacy of these plans and what tools, capabilities, and/or conditions are required before advancing towards greater adoption of full-scale IDP?
- What are the key elements of an IDP? What are the phases of advancement starting from traditional planning to future phases of IDP?
- What challenges and considerations need to be evaluated as utilities, regulators, and other stakeholders transition through various phases of maturity in IDP?

2 Distributed Energy Resource (DER): DERs are physical and virtual assets that are deployed across the distribution grid, typically close to load, and often behind the meter, which can be used individually or in aggregate to provide value to the grid, individual customers, or both. DERs discussed in this paper include technologies such as solar, energy storage, electric vehicles, and load flexibility/demand response.

3 Wood Mackenzie as cited in Greentech Media (2020), What the Coming Wave of Distributed Energy Resources Means for the U.S. Grid.

4 The Brattle Group (2020), Getting to 20 Million EVs by 2030 Opportunities for the Electricity Industry in Preparing for an EV Future, p. 3.

Background

Before exploring IDP elements and challenges, it is important to establish a clear understanding of IDP, how it differs from traditional distribution planning, and what is driving this transition. While a few states have started to establish IDP processes (e.g., California, New York, and Hawaii), the industry is still working to develop a deeper understanding. In IDP processes unfolding in other states, utilities and stakeholders are working to unpack the complexities behind IDP and evaluate possible steps required to get from where they are today to where distribution planning processes may need to be. This paper in no way infers that today's utility planning process has not been effective, but rather discusses the continuous change brought on by new drivers and changing needs.

Navigating Different Terminology and Approaches to Integrated Distribution Planning

Utilities and industry experts use a variety of terms to describe integrated distribution planning processes, including "enhanced distribution planning," "distribution resource planning," and "integrated grid planning." For utilities, the differences in terminology are often dictated by their unique market, system, and regulatory conditions. A few examples of different terminology include:

- Hawaii's Integrated Grid Planning (IGP),
- California's Distribution Resource Planning (DRP),
- New York's Distribution System Implementation Plans (DSIP), and
- Minnesota's Integrated Distribution Plan (IDP).

While multiple terms exist to describe distribution planning processes of the future, industry labs, associations, and research organizations have coalesced around the term "integrated distribution planning" (IDP).[5]

The states listed above each take a different approach to integrated distribution planning. As a vertically integrated utility, Hawaiian Electric Company's (HECO) IGP process has an emphasis on the coordination and integration of generation, transmission, and distribution planning processes into one comprehensive approach. California's DRP and New York's DSIP processes differ as well, fulfilling goals and pursuing outcomes unique to each state. While both processes involve identifying optimal locations for potential NWAs, California's DRP process includes approval and procurement as part of the DRP, whereas in NY, approval and procurement is done outside of the DSIP process. The DSIP process in NY emphasizes increased transparency and visibility into how utilities operate the grid and supports the State's goal of transforming the grid into a Distribution System Platform (DSP). Minnesota's IDP has similar characteristics to the approaches in HI, NY, and CA (e.g. focus on TDG integration, DER valuation, and increased transparency into the planning process) and views IDP as an integral piece to grid modernization in their state.[6]

When reading this report it is important to remember that no "one-size fits all" solution exists, and utility planning processes will look different based on their unique situations.

5 This terminology is used by multiple organizations including GridLab, the Mid-Atlantic Distribution Resources Initiative (MADRI), the U.S. Department of Energy (DOE), and others. Though the terminology is the same, there are subtle differences in how each group approaches the topic. In many cases the "integrated" portion of IDP references integration of NWAs and other potential solutions to grid constraints into the planning processes. For example, MADRI's *Integrated Distribution Planning for Electric Utilities: Guidance for Public Utility Commissions* report states, "The most essential factor that separates an IDP from a traditional distribution planning process is the integrated considerations of all possible solutions to identified needs." In other cases, the term "integrated" refers to increasing coordination between transmission, distribution, and generation planning as well as other activities within the utility. This report explores both of these integrations as well as integration of processes within common elements of distribution planning.

6 Paul De Martini, ICF International, Minnesota Public Utilities Commission (MPUC) (2016), Integrated Distribution Planning, p. 21.

Defining Integrated Distribution Planning

Often, IDP has been loosely defined around the drivers to which it is responding, or the outcomes it is trying to achieve. For a number of states and utilities, this has included the desire to effectively integrate rapid DER adoption, evaluate non-wires alternatives (NWAs), and/or incorporate greater stakeholder engagement and transparency into the distribution planning process.

While these can be important components of IDP, SEPA defines IDP using a holistic perspective that centers around two key traits:

1. Integration of internal elements and processes within the utility to enhance distribution planning, and
2. Integration of distribution planning with transmission and generation planning (as it applies).

This paper examines IDP predominantly through a distribution lens. This includes evaluating how distribution planning processes may need to become more integrated internally (i.e., separate planning processes, planning and operations groups). Discussion of integration among transmission, distribution, and generation (TDG) planning is also focused through a distribution lens and examines how distribution can become more coordinated and integrated with transmission and generation planning.

Transitioning from Traditional to Integrated Distribution Planning

Common distribution planning practices at utilities, referred to as "traditional distribution planning" in this paper, focus on assessing the performance of the grid within the context of anticipated changes in load along the system. These efforts were established based on core requirements for all utilities to provide safe, reliable, and affordable delivery of electricity to customers.

In traditional distribution planning, utility engineers forecast load growth and peak demand topologically at the feeder and substation levels of the distribution system, or spatially based on geographic location of customer loads. Utilities focus on the conditions of the distribution grid based on these forecasts, using planning criteria that accounts for system reliability and risk. After forecasting is complete, distribution planners flag any future planning criteria violations to identify grid needs, and evaluate potential solutions. In these circumstances, solutions typically include "traditional" assets such as poles, wires, transformers, voltage regulators, and other utility equipment. This process has historically been internal to the utility, with limited engagement with stakeholders.

Industry Trends Influencing the Transition towards IDP

For many utilities, traditional distribution planning has met and continues to meet core needs for providing safe, reliable and affordable delivery of electricity. However, growing DER adoption, changing customer behaviors, and other factors are bringing greater complexity to the distribution grid, and prompting reevaluation of current distribution planning practices. Key trends include:

- **Increasing DER Adoption:** According to EnerKnol Research, states initiated more than 30 pro-DER policies in 2019.[7] These policies included, among other topics, direct investigation into distribution planning, improvements to interconnection standards and procedures, review of community distributed generation program requirements, and notices of DER pilot programs.[8] Policies such as these will likely lead to an increase in DER adoption with cumulative DER investments projected to eclipse $80.6 billion between 2020 and 2026.[9]
- **Electrification:** Electrification also has the potential to significantly impact system planning. According to The Brattle Group, fully electrified heating and transportation has the potential to add up to 3,000 TWh of electricity demand in the U.S. by 2050.[10] Electric vehicle (EV) adoption alone is projected to significantly increase over the next decade with projections ranging from 10 to 35 million EV sales by 2030.[11] The shift towards EVs can significantly impact load and planning along the distribution system, with The Brattle Group further estimating that 20 million EVs will add 60-95 TWh of electricity demand per year, 10-20 GW of peak load and require $75 to 125 billion of investments across the electric power sector.[12]

7 EnerKnol Research (2019), States Reexamine Policies to Accommodate Distributed Generation Growth.
8 EnerKnol Research (2019), States Reexamine Policies to Accommodate Distributed Generation Growth.
9 Wood Mackenzie (2020), The next five years will see massive distributed energy resource growt.
10 The Brattle Group (2018), New Sources of Utility Growth Electrification Opportunities and Challenges.
11 The Brattle Group (2020).
12 The Brattle Group (2020).

Distinguishing Between Traditional and Integrated Distribution Planning

Though traditional distribution planning and IDP may look different at each utility, a handful of key traits help distinguish ways IDP departs from traditional practices. Table 1 below summarizes the differences between traditional and integrated distribution planning.

A small number of utilities are using formal IDP processes representing traits listed in Table 1, while a much larger number of utilities are using processes exhibiting some traits of IDP. For example, utilities may be working towards expanded goals and objectives, evolving their forecasting capabilities, or looking at non-traditional solutions to grid needs outside of a more explicit IDP process.

Table 1: Transitioning from Traditional to Integrated Distribution Planning

Traditional Distribution Planning ←	→ Integrated Distribution Planning
Core requirements/objectives: Safe, reliable, affordable grid.	**Expanded vision, goals, & objectives:** Expands beyond safe, reliable, affordable grid; May account for: ▪ clean energy goals, ▪ grid flexibility, ▪ market animation,[13] and ▪ customer options and enablement.
Internal process within a utility.	Increasing communication, both internally at the utility and externally with **stakeholder engagement** (e.g., help stakeholders understand technical and economic decisions, provide input at defined steps of the process).
Primary distribution grid concerns focused on thermal overloading and abnormal voltage conditions during a steady state.	**Distribution grid concerns expand** to increasingly include undervoltage, overvoltage, and dynamic power quality impacts.
Deterministic forecasting analysis based on historical/ peak loads and traditional load growth trajectories.	**Increasingly complex and advanced forecasting analysis** incorporating load forecasting with more granular data and DER forecasting. Includes temporal/hourly forecasts to support evaluation of time/energy/limited resources and their locationality.
DERs included in forecast but **seen as a load modifier**; active targeting of location and DER operation not included in development of planning. **Sourcing solutions** to alleviate grid constraints **limited to traditional utility equipment.**	**Proactive approach to DERs** in planning; Planners evaluate traditional and non-traditional solutions (e.g., non-wires alternatives) in response to constraints along the system; guide DER deployment in optimal locations.
Distribution planning is mostly separate from transmission and generation planning processes.	**Increasingly coordinated and integrated processes** between distribution, transmission, and generation planning (as applicable); work closely with system operations as well.

Source: Smart Electric Power Alliance, 2020.

13 New York Reforming the Energy Vision (NY REV) example of market animation: REV will establish markets so that customers and third parties can be active participants, to achieve dynamic load management on a system-wide scale, resulting in a more efficient and secure electric system including better utilization of bulk generation and transmission resources.

EV sales are also not uniform across the country, making it necessary for some planners to develop locational-specific adoption forecasts to account for impacts to the system.

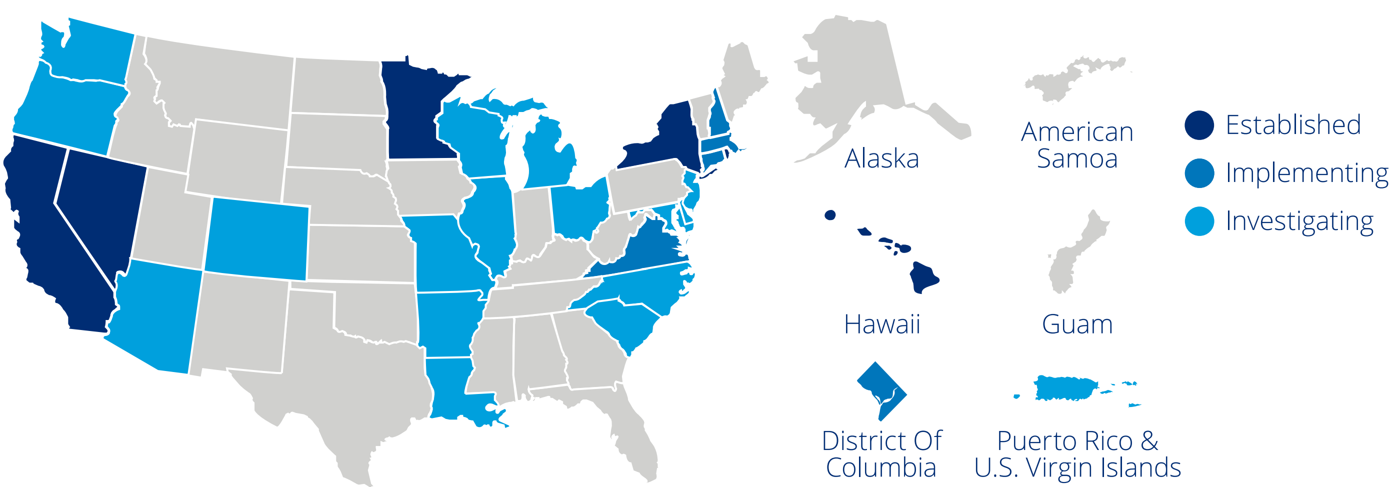
- **Resilience:** In 2020 thus far, there have been 10 extreme weather events with losses of over $1 billion each in the United States (U.S.).[14] This marks the seventh consecutive year in which 10 or more billion-dollar weather and climate disasters have occurred in the U.S.[15] These and other events have made resilience a key driver for evaluating current planning processes as utilities harden the distribution system to mitigate against natural disasters and other potential threats in the future.

Challenges to Distribution Planning and Grid Capabilities on the Horizon

Trends such as those listed in the Industry Trends Influencing the Transition towards IDP section have the potential to involve a much greater level of complexity and related technical considerations when considering the traditional distribution grid's capabilities and planning processes. Key technical challenges faced include:

- **Visibility and Control of DERs:** Most utilities have little to no control over the size, type, and location of DERs that customers are interconnecting along their system. As more customer-sided resources are interconnected, utilities will need improved monitoring of DER operations and programs that incent DER owners to operate in a manner that benefits the grid, or allow utility control of DERs under certain circumstances. With forecasting playing a key role in distribution planning, utilities will also increasingly need to be able to request or access third-party developers' forecasts to inform the planning process.
- **Evolving DERs:** The grid-facing capabilities of DERs are changing in parallel to their growing numbers. For example, the majority of demand response (DR) technologies on the grid are load control switches; however, this is changing as more behavior-based and intelligent DR technologies are installed.[16] New standards like IEEE 1547-2018 require that all generation-based DERs support smart capabilities allowing them to provide active and reactive power support automatically or when solicited. In addition, newer technologies are evolving to enable managed charging, microgrids, and grid-interactive efficient buildings. This combination of changing and emerging DER capabilities will morph what a DER means to utilities today into the dynamic, grid-supportive resource they will become tomorrow. A key role of IDP will be understanding these capabilities and aligning forecasting, planning, and operations to address them.

Figure 1: State Integrated Distribution Planning Activities



Source: SEPA, EPRI, LBNL, 2020.[17]

14 National Centers for Environmental Information (NCEI) (2020), Billion-Dollar Weather and Climate Disasters.

15 NCEI (2020).

16 Smart Electric Power Alliance (2019), 2019 Utility Demand Response Market Snapshot; The Brattle Group (2019), The National Potential for Load Flexibility.

17 Electric Power Research Institute (EPRI) as cited in Lawrence Berkeley National Laboratory (LBNL) (2020), Distribution Planning Regulatory Practices in Other States.

- **Limited tools and data capabilities:** Current tools and data capabilities (e.g., metering, measurement locations, data analytics) limit a distribution planner's ability to determine customers' characteristics such as their net energy usage, the available output from their DERs, and predictive information such as weather that may impact performance.

When DER adoption is low, these factors may have less impact on the distribution network, but as DER adoption increases and potential locational clustering occurs, the utility monitoring and control process can face increasing technical challenges. Utilities will face multiple challenges with regards to visibility, tools, and resources (e.g., skilled staff, investments) needed to manage DERs while maintaining system safety, reliability and efficiency. The desire to get in front of these challenges has been a driver for utilities investigating IDP.

Table 2: State IDP Objectives and Goals

State	Objective/Goal/Vision
New York	▪ Transition to a Distribution System Platform (DSP) and enable efficient investments in DERs ▪ Roadmap for technology investments to improve the intelligence of the grid and prepare for higher DER penetration levels ▪ Provide data to bring greater transparency to the planning process ▪ Address the tools, processes, and protocols needed to plan and operate a modern grid[18]
California	▪ Modernize the electric distribution system to accommodate two-way flows of energy and energy services throughout the IOUs' networks ▪ Enable customer choice of new technologies and services that reduce emissions and improve reliability in a cost-effective manner ▪ Animate opportunities for DERs to realize benefits by providing grid services[19]
Hawaii	▪ Comprehensive, customer centric, planning and sourcing process ▪ Identify and enable the optimal mix of DER, DR, and grid-scale resources ▪ Harmonize resource, transmission, and distribution planning processes[20]
Minnesota	▪ Enhance the customer experience ▪ Lead the clean energy transition ▪ Keep customer bills low ▪ Safe, reliable, affordable electric service—with an eye to the future[21]
Rhode Island	▪ Identify and reveal spatiotemporal value on the distribution system ▪ Source DER solutions from the marketplace ▪ Guide investment decisions by the utility, customers, and third-parties[22]
Nevada	▪ Evaluate locational benefits and costs of distributed resources ▪ Propose standard tariffs, contracts, or other mechanisms for the deployment of cost-effective distributed resources ▪ Coordinate existing programs approved by the Commission ▪ Identify spending necessary to integrate cost-effective distributed resources ▪ Identify barriers to deployment of distributed resources[23]

Source: Smart Electric Power Alliance, 2020.

18 New York Joint Utilities (2016), Supplemental Distribution System Implementation Plan, p. 1-2.

19 California Public Utility Commission (CPUC) (2015), Assigned Commissioner's Ruling on Guidance for Public Utilities Code 769—Distribution Resource Planning.

20 HECO (2018), Planning Hawaii's Grid for Future Generations: Integrated Grid Planning Report.

21 Xcel Energy (2019), Integrated Distribution Plan.

22 Division of Public Utilities & Carriers, Office of Energy Resources, and Rhode Island Public Utilities Commission (2017), Rhode Island Power Sector Transformation, p. 44.

23 Nevada State Legislature (2017), SB146: AN ACT relating to energy; requiring certain electric utilities in this State to file with the Public Utilities Commission of Nevada a distributed resources plan, p. 1.

Regulatory, Board, and Community Drivers

Utilities with established IDP processes, or who are in the midst of implementing or investigating IDP opportunities, have regulatory activities and board mandates as a common driver for investigating their distribution planning processes. Behind these regulatory activities are expanded objectives, goals, and visions for each state that require a more integrated distribution planning process to support the clean energy transition, enable customer options, and increase operational efficiency. Regulatory activities have taken place in 26 states, the District of Columbia, and Puerto Rico (see Figure 1) under which commissions and utilities are investigating, implementing, or have established IDP processes. In addition to state regulatory activity, cities and utilities are adopting clean energy goals, thus accelerating drivers for enhancing distribution planning. 165 cities and towns are committed to or powered by 100% clean energy.[24] Similarly, 56 utilities in the U.S. have. publicly-stated carbon or emissions reduction goals.[25] Enhancing today's distribution planning processes and investing in modernizing the grid is required to reach these goals and objectives. Examples of objectives driving IDP are outlined in Table 2, based on states with established IDP processes (see Figure 1).

Figure 1 displays state regulatory activity around utility distribution planning. Twenty-six states, the District of Columbia, and Puerto Rico are represented as either investigating (18), implementing (4), or have established (6) enhanced distribution planning processes. States marked as "investigating" have regulatory dockets open or grid modernization initiatives in progress, which are exploring components of IDP and/or distribution planning requirements. States marked as "implementing" have updated requirements for distribution planning and utilities are filing or seeking approval for their initial plans under the new requirements. In states marked as "established", distribution planning requirements have been updated and utility distribution plans under the new requirements have been approved by the commission and executed by the utility(ies).

Demystifying Integrated Distribution Planning

While IDP will be unique to each utility, Figure 2 illustrates a general IDP process, focusing on the elements highlighted by many regulators, utilities, and other stakeholders. Understanding these elements will provide a foundation for the SEPA IDP phased framework discussed in the subsequent section.

The IDP process will be informed by multiple inputs and considerations, as well as by the needs of the utility and other stakeholders. IDP may include elements of distribution planning that are increasingly integrated. We explore both of these areas in the sections that follow.

Understanding Context and Starting Points: Key Inputs and Considerations

As utilities begin to investigate IDP, they should first establish a deep understanding of the goals and factors driving changes in their regions, the capabilities of their existing distribution system, and the potential challenges or limitations that may exist. The utilities and states that are approaching IDP have unique starting points, based on a number of factors, including: market and regulatory structure, infrastructure conditions, system loading and DER adoption, capital plans, and existing tools and supporting operational infrastructure. The IDP process can and likely will be different for individual utilities and states, based on a number of inputs and considerations. The following sections discuss how key inputs and considerations may determine a utility's starting point, and inform how utilities may incrementally advance towards their future IDP process.

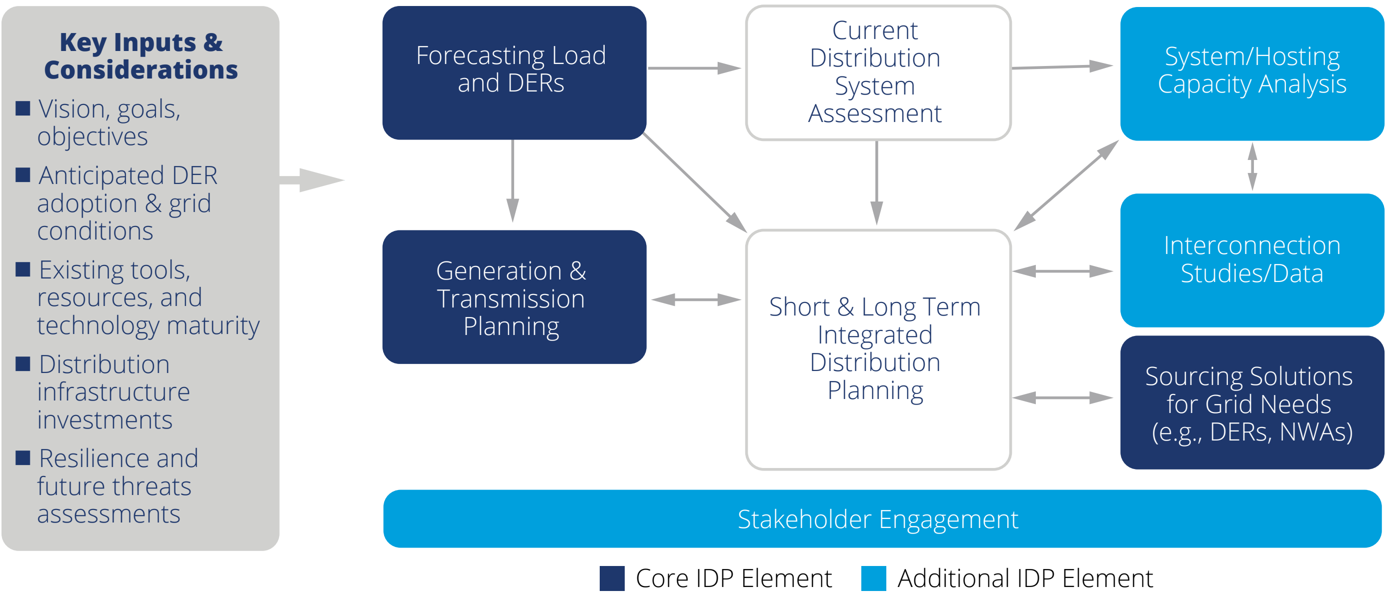
Vision, Objectives, and Goals

Utilities have historically focused their planning and operations on the universal objectives of providing safe,

24 Sierra Club (2020), Ready for 100.

25 Smart Electric Power Alliance (2020), Utility Carbon Reduction Tracker.

Figure 2: Integrated Distribution Planning Process



Source: Adapted by Smart Electric Power Alliance based on Department of Energy (DOE) (2017), Modern Distribution Grid Decision Guide Volume III, 2020.

reliable, and affordable electricity to their customers. The industry is undergoing a transformation as clean energy policies, DER adoption, and changing customer expectations lead to expanded visions, goals, and objectives for states and utilities. While these historical requirements to deliver safe, affordable and reliable power remain, the expectations and vision for how the utility of the future will operate is evolving. As illustrated in Table 2, an expanding set of goals and objectives are driving changes for utilities' distribution planning efforts. Beyond traditional safe, reliable, and affordable objectives, expanded goals and objectives influencing utilities' transition to IDP may include:

- **Customer options and enablement:** Expand planning processes and programs to provide customers the opportunity to adopt new technologies and services.
- **DER integration and market animation:** Help integrate DERs and provide opportunities for innovative products and services to participate on the grid.
- **Operational efficiency:** Optimize grid and DER operation through grid modernization and expanded planning methods to reduce losses, increase DER output, and eliminate system constraints.

A clear understanding of the objectives and goals of the utility and its jurisdiction[26] is important to guide utilities' and stakeholders' understanding of how IDP may support such efforts.[27]

Accounting for Anticipated DER Adoption and Grid Conditions

As discussed earlier, increasing DER adoption has the potential to pose challenges along the distribution grid. The need for IDP is not dependent solely on DER adoption rates, and should be examined within the context of grid conditions. For a number of utilities and states, system-wide DER adoption is not yet at the point that it will cause systemic challenges to the distribution grid. However, critical points are more likely reached on a feeder-by-feeder basis, and will vary depending on each utility's asset conditions and infrastructure design.

Grounding IDP plans with an assessment of existing and anticipated DER adoption on a feeder-by-feeder or substation-by-substation basis will help inform utilities' starting points, and will identify the immediate needs and possible lead times available for implementing elements of IDP.

Assessing Existing Tools, Resources, and Available Technology

The existing tools, technology and systems deployed, as well as staff capabilities at a utility can be limiting factors

26 The term "jurisdiction" in this paper is used to reference the footprint of a utility and its governing body.

27 Pacific Northwest National Laboratory (PNNL) (2018), Distribution System Planning – State Examples by Topic, p. iv.

for implementing IDP processes. These considerations can also impact the ability to realize potential IDP goals as well as the steps taken. For example, a later stage IDP process will require more sophisticated connections to operational systems in order to sense, collect, manage, and analyze the required data. As more resources along the grid are not controllable by the utility, the utility may require more granular data on system conditions, DER output, customer behavior, and locational and temporal forecasts. The ability of utilities to collect, analyze and leverage this data varies. For some, existing technology and software may allow them to start with an advantage over those who may require further grid and technology investments to build these tools and capabilities.

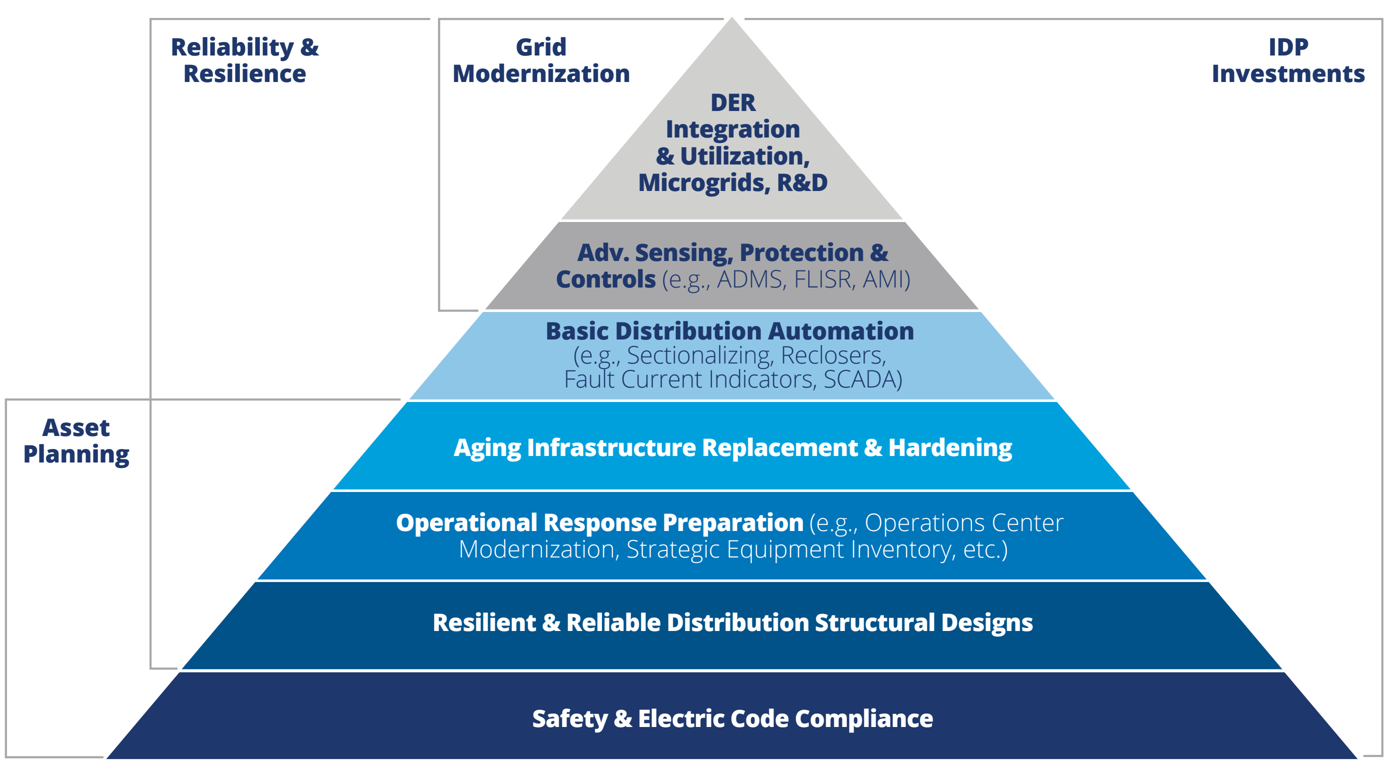
In some cases, a utility may want to advance to a more mature state of IDP, but their tools and technologies may not be at a commercially mature enough stage for deployment. These factors influence implementation considerations of certain IDP elements, and are addressed in following chapters. An assessment of commercial technology gaps in supporting IDP is required, but beyond the scope of this report.

Distribution Infrastructure Investments: Current and Planned

Utilities starting points, in terms of existing grid investments (e.g., physical infrastructure, operational technologies,[28] advanced protection and controls, sensing and situational awareness, planning tools and models) and their success in gaining approval for and implementing new technologies and investments will help enable elements within the IDP process. Distribution capital spending encompasses a broad range of investments and is not limited to distribution planning investments. Considering distribution planning investment needs in the context of plans for asset planning, reliability and resilience, and grid modernization will be necessary as the industry looks to transform the electric utility industry. For example, moving distribution planning processes towards IDP will require investment in planning tools and other grid investments, but these should not be viewed as separate from the investments required in the physical grid to accommodate high levels of DERs.

Investment in distribution infrastructure is part of a foundation of capital and operational investments that includes asset planning, reliability and resilience, and grid

Figure 3: Distribution Infrastructure Investment Prioritization Pyramid



Source: Paul De Martini with modifications by Smart Electric Power Alliance, 2020.

28 Examples may include supervisory control and data acquisition (SCADA), advanced distribution management systems (ADMS), and distributed energy resources management systems (DERMS).

The Need for an Integrated and Holistic Approach to Distribution Investments

A common challenge for regulated utilities is the process of justifying distribution investments to regulators. Investor-owned utilities have to demonstrate the prudence of making investments and that assets will be "used and useful"[29] to customers, while cooperatives and public power utilities must demonstrate customer value when investing in new technologies. All involve demonstrating that the benefits of the investments outweigh the costs. In some regulated environments, grid modernization investments have sometimes been viewed in a silo (e.g., as investments to integrate DERs) without explicitly accounting for the value those investments may also provide to the distribution system, and therefore are not integrated in planning processes. For regulated utilities, this has at times resulted in:

- Investments to integrate DERs are not treated the same as other distribution investments considered in distribution planning
- Challenges in justifying distribution investments via traditional benefit-cost frameworks
- Distribution investments being utilized for a specific use case, but its additional value to the distribution system cannot be quantified

Example—Unlocking Additional AMI Value for Distribution Planning: *In some cases, utilities have deployed AMI, and justified the investments based on benefits for specific use cases, such as providing or improving remote meter reading. As they look to leverage AMI data for distribution planning, utilities may find that further investments in back office capabilities—information technology (IT) or operation and maintenance (O&M)—are required to integrate AMI data and fully utilize the prior investments to enhance their planning processes. In these cases, the primary direct benefits (e.g., reduced meter reading costs) have already been captured in making the AMI investments. The indirect (or enabling) benefits (e.g., enhanced visibility for distribution planning, expanded options for customer programs) are harder to quantify and justify as they may depend on actions being taken by others (e.g., customers responding to time varying rates enabled by AMI). In these cases, utilities will need to make the case that benefits exceed the costs by incorporating these indirect benefits, and regulators may need to think more broadly or consider modifications of their processes to take more indirect benefits into account.*

modernization investments (see Figure 3).[30] IDP is interrelated with investments across these three classifications (i.e., asset planning, reliability and resilience, and grid modernization). For example, IDP may identify assets that require replacement to serve future grid needs or to harden the grid based on latest planning requirements. Additionally, IDP efforts may require advanced sensing, protection, and control as well as DER integration and other grid modernization investments to enable advanced planning and operational capabilities in the future.

Before advancing towards IDP, utilities will need to assess existing investments and understand their investment priorities in relation to the goals and objectives driving the process.

Resilience and Future Threats to the System

For certain utilities, increasing their resilience against man-made threats and natural disasters is an important factor when considering short- and long-term distribution planning. Climate change and development in disaster prone areas is causing an increase in the number, magnitude and costs of natural disasters. This, coupled with the increasing complexity of the distribution system due to the rise in DER penetration, has necessitated new, integrated approaches to planning in order to ensure system awareness and control.

Utilities are increasingly considering resiliency solutions as part of their overall planning process. This can involve investing in different resilience solutions, similar to historical utility investment in reliability and capacity solutions. Efforts are going beyond the earlier focus on hardening infrastructure to consideration of other solutions, such as alternative circuit designs, advanced technologies, and microgrids to help increase the reliability of the system.[31]

29 For investor-owned utilities, the standard legal/regulatory terms for approval is "prudent, used and useful." Cooperative and public power utilities have to justify investments but do not have to meet the legal standards that IOUs encounter.

30 U.S. Department of Energy (DOE) Office of Electricity (2020), DSPx Volume IV (Forthcoming report).

31 U.S. Department of Energy (DOE) Office of Electricity (2020), DSPx Volume IV (Forthcoming report).

Elements of Integrated Distribution Planning

Once the utility and its stakeholders understand the goals and circumstances that may influence movement towards IDP, they can begin to determine the elements that compose their IDP process. This section describes the IDP process shown in Figure 2, and provides a high-level overview of the IDP process, its potential elements, and how the distribution planning process can become increasingly integrated.

Two common aspects of IDP are: An assessment of the current distribution system, and short-term and long-term distribution planning cycles.

Current Distribution System Assessment: The IDP process typically includes an assessment of the current distribution system, in which current system capabilities are compared with load forecasts, potential DER growth and "default" or historical DER operation characteristics to identify constraints and conditions of grid assets. Early in the process, utilities run rigorous power flow analysis, and conduct asset conditions and system reliability assessments to examine the current system's ability to provide safe, reliable service. These steps assess the reliability of current feeders and substations as well as the conditions of grid assets, asset loading and operations.[32,33] As utilities understand customer needs, this element of the IDP process will help identify where these needs may exceed the capabilities and capacity of the system, and highlights opportunities where DERs may play a larger role in the distribution system.

Short- to Long-term Integrated Distribution Planning: As shown in Figure 2, a number of elements may inform or be informed by distribution planning, and likely include short-term as well as long-term planning outlooks.

- **Short-term distribution planning** may take place on an annual or bi-annual basis to help determine the near-term (one to two-year) incremental grid needs and opportunities for improving operational performance.[34]
- **Long-term distribution planning** is more strategic and holistic than short-term planning, and may have an outlook of 10 to 15 years. This effort evaluates the significant grid changes that may be needed in the future, and examines the large-scale trends and potential changes to the system that may warrant longer-term adjustments. In contrast to short-term planning, this may more fully incorporate strategic forecasting and analysis (e.g., multiple-scenario-based analyses) and evaluating traditional versus non-traditional solutions, as well as align more with generation and transmission planning, as applicable.[35] Long-term integrated distribution planning is the primary focus of this paper.

Core IDP Elements

While IDP may look different from utility to utility, three IDP elements—forecasting, sourcing solutions for grid needs, and generation and transmission integrated planning—are central to the transition from traditional to integrated distribution planning. A high-level overview is provided in this section as a prelude to discussing how these elements may evolve in a phased progression framework (see subsequent chapter for greater detail).

Forecasting: Central to the evolution of distribution planning is the move away from "snapshot" peak load forecasts towards more sophisticated forecasting analyses that account for increased granularity, changing customer needs, temporal variation, DER adoption trends, and expanded demand flexibility. Traditional planning processes and the capabilities of utilities are largely constrained by limitations in visibility of DER performance and output. Future IDP capabilities with forecasting assume expanded capabilities in collecting and analyzing granular data to produce temporal forecasts and help inform long-term planning.[36] IDP forecasting will also increasingly incorporate DER forecasting methods that accommodate expected levels of DER participation and operation as technology and tools continue to mature.

Sourcing Solutions for Grid Needs: As technology matures, more opportunities will emerge to incentivize and optimize DERs and other solutions for grid services. The IDP process may include methods to evaluate DERs and other non-traditional solutions in response to potential constraints along the system. The most common approach to date has been through one-off evaluations of non-wires alternatives (NWAs), or integration of NWA screening and evaluation processes within IDP.

32 U.S. DOE Office of Electricity (2017), Modern Distribution Grid Decision Guide Volume III, p. 46.

33 Paul De Martini, ICF International, Minnesota Public Utility Commission (2016), Integrated Distribution Planning, p. v.

34 U.S. DOE Office of Electricity (2017), Modern Distribution Grid Decision Guide Volume II, p. 12.

35 U.S. DOE Office of Electricity (2017), Modern Distribution Grid Decision Guide Volume II, p. 12.

36 Smart Electric Power Alliance (2020), Utility Sponsor Interviews; Interview with Paul De Martini, (2020).

While debate continues on the best methods for sourcing solutions (e.g., programs, procurement and/or pricing[37]), evaluating the benefits and costs of NWAs, and conducting locational value analysis, the overall process of evaluating where DERs and other non-traditional solutions may best support the distribution grid, can be an important element in the IDP process.

Generation and Transmission Planning: Distribution planning has typically taken place separately from generation and transmission planning. As DER growth continues, more regions may need to explore the increased coordination and potential integration of these planning processes. This is particularly true in cases where DERs may be called on to serve multiple purposes (e.g. fast frequency response, capacity/generation dispatch, distribution contingency mitigation, etc.) to ensure dispatch of DERs for one use case does not adversely impact another. There will be an increased need to align DER growth patterns, timing, and load shape assumptions across generation, transmission, and distribution planning, via an iterative process.[38]

Additional IDP Elements

The following additional elements may play a prominent role in IDP, depending on the circumstances and goals of the utility and its stakeholders.

Interconnection—Information Integration: Data from the interconnection process and interconnection studies can help inform planners of the size, location, type, capabilities, and settings of DERs connecting to the grid. As more customers look to interconnect DERs and as the types of technologies, their configurations, and the ability to pair technologies together expands (e.g., solar plus storage), enhancing the interconnection process to effectively capture, digitalize, and utilize this information will become increasingly important to enable future IDP processes.

Hosting Capacity Analysis (HCA): Hosting capacity is the amount of customer-driven generation-based DER that can be accommodated without impacting critical factors on the system (e.g., reliability, power quality, and voltage) under existing grid infrastructure, control and protection systems.[39] The importance of HCA and its role in IDP is dependent on the goals and uses for HCA, which will inform the approach for conducting HCA (e.g., level of automation, depth of analysis, frequency of analysis, and level of integration with other systems) and its relevance to IDP.

Utilities conducting this analysis may do so for internal knowledge or as a method to inform customers and third-parties of the constraints on the grid (e.g., thermal, voltage/power quality, and protection limits). Additionally, hosting capacity can provide a valuable indicator regarding the criticality of DER planning (e.g., if hosting capacity is largely unconstrained, implementation of full scale IDP may be less urgent than if hosting capacity is constrained across a large number of feeders). Its importance in the IDP process is dependent on the system conditions a utility is facing, the process by which it is incorporating third parties into its distribution planning process, and the needs of third-parties and customers.[40]

Stakeholder Engagement: IDP also offers an opportunity for increased transparency into the distribution planning processes, and the ability to inform and obtain input from stakeholders. The main avenue for achieving greater transparency is via stakeholder engagement, which has been a component of a number of IDP processes in Hawaii, California, Minnesota, and other states. Increased transparency through stakeholder engagement can lead to more support for investments, innovative solutions to grid constraints, as well as other benefits. The ways utilities increase transparency and solicit input from stakeholders is dependent on the type of utility (e.g., investor-owned utility, cooperative, public power), regulatory directives, and the needs of its stakeholders. Where within the IDP process to engage stakeholders, and how (e.g., open versus closed processes, working groups, iterative processes, etc.), will vary.

37 Often referred to as the "three Ps" to describe the broad set of sourcing methods for obtaining DER services. These are defined within Rocky Mountain Institute's *Non-Wires Solutions Implementation Playbook* (2018) as:

__Customer Programs__ encompass demand side management offerings in which the utility compensates customers for participating in measures including energy efficiency, deviceenabled demand response programs (e.g., smart air conditioning or smart thermostat programs), pricing-based demand response programs (e.g., peak-time rebates), and behind-the-meter generation and storage.

__Pricing Mechanisms__ involve changes to customer tariffs, including time-of-use rates, demand charges, critical peak pricing (CPP), variable peak pricing (VPP), real-time pricing (RTP), net-metering (NEM), feed-in-tariffs (FITs), and New York's Value of DER (VDER).

__Procurements/Competitive Solicitations__ are standalone procurements in which a utility asks the market to competitively offer solutions, typically through a request for proposals (RFP) or an auction process.

38 U.S. DOE Office of Electricity (2017), Modern Distribution Grid Decision Guide Volume III, p. 46.

39 U.S. DOE Office of Electricity (2017), Modern Distribution Grid Volume I: Customer and State Policy Driven Functionality, p. 62-63.

40 Smart Electric Power Alliance interview with Samir Succar, (2020).

Phased Integrated Distribution Planning Framework

Overview of Phased IDP Framework

Each utility will approach IDP from a unique starting point (see Understanding Context and Starting Points: Key Inputs and Considerations), and the desired goal for distribution planning will differ from utility to utility, depending on the goals and vision for the future grid. In addition, any change is not instantaneous, but is likely to happen over time as incremental changes are made to incorporate new or modified processes, technologies, and policies. The transition from traditional to integrated distribution planning is therefore both varied and a phased approach. Figure 4 illustrates the phased progression of each element of IDP, starting from a traditional planning process and advancing to an aspirational future IDP state.

A few assumptions should be noted as utilities, regulators, and stakeholders look to this framework for guidance:

- **Elements included in each utility's IDP may vary:** The core and additional elements included in a utility's IDP process may vary in importance depending on the vision, goals, and objectives. Regulatory constructs and grid limitations all influence the starting points and end states for IDP.
- **Key considerations and challenges:** Progressing to more advanced phases (e.g., Phase 3, Phase 4) will depend on a number of considerations (e.g., technology implementation, organizational capability) and challenges, detailed by element and phase in subsequent chapters.
- **Interdependencies and increased integration:** While some coordination may take place between some IDP elements in earlier phases (Phases 1 and 2), there will be increased coordination and integration between IDP elements as well as systems and tools as utilities advance towards more mature phases (Phases 3 and 4).
- **Phases may vary by element:** Utilities may exist in different phases at the same time (e.g., Phase 2 Forecasting and Phase 1 Hosting Capacity). This framework does not imply that a utility must operate at the same phase across all IDP elements.
- **Phase 4 may not be an appropriate end state:** Phase 4 detailed across IDP elements (see Figure 4) points to a more aspirational future state to guide the progression of IDP. SEPA cautions against expectations for all utilities to meet at Phase 4, and emphasizes the need to first take thoughtful consideration to the goals utilities and those in its jurisdictions are trying to meet.

Integration of Distribution Planning

A less explicit but crucial component of IDP is the "integration" of distribution planning. This may take place across a few dimensions and is contingent on increased grid investments, regulatory changes (as applicable), and internal change management, as detailed in Figure 5.

Traditional practices and elements in the distribution planning process are not typically closely coordinated with one another. As utilities transition towards later phases of IDP, the integration of distribution planning may take place along multiple dimensions, including:

- **Integration and greater coordination between different elements of IDP:** As technology and capabilities develop and utilities advance to more mature phases of IDP, there will be greater need and ability to coordinate and integrate these elements with one another. This is discussed in greater detail in the subsequent sections.
- **Increased coordination between transmission, distribution, and generation:** The future energy system may bring about new challenges to the grid, and will require increased coordination between transmission, distribution, and generation planners.
- **Distribution planning examined holistically with asset management, grid modernization, and resilience planning:** Beyond looking at investments holistically, there is a need to examine asset management, grid modernization, resilience planning and capacity planning together when considering planning and investing in the electric grid. As utilities progress through the phases, there may also be integration of these often separate efforts and consideration of DERs for their grid services.

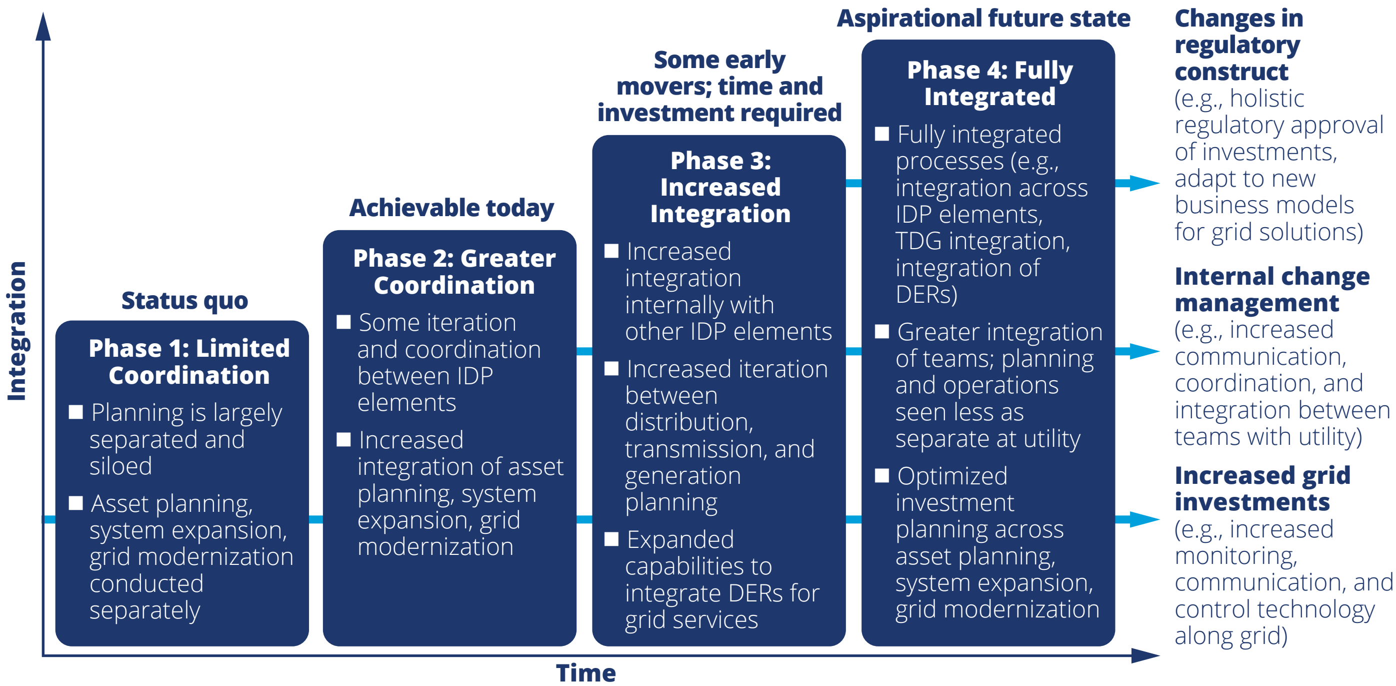
Figure 4: Phased Integrated Distribution Planning Framework

		Phase 1	Phase 2	Phase 3	Phase 4
Core IDP Elements	Forecasting	Load forecasting with limited visibility	Load forecasting with standard visibility	Load forecasting with increased visibility	Advanced, integrated granular forecasting
Core IDP Elements	Sourcing Solutions for Grid Needs	DERS not considered to address distribution system needs	Piloting DERs and non-traditional solutions	Evaluation of DERs and non-traditional solutions integrated in IDP process	Streamlined DER solutions sourcing based on locational and temporal value
Core IDP Elements	Transmission/ Distribution/ Generation Integration	Siloed planning processes	Annual, iterative approach	Increasingly iterative approach	Continuous, co-optimized planning processes
Additional IDP Elements	Interconnection	Manual process	Increasingly digitized and streamlined process	Increasingly automated and streamlined process; coordinated with other IDP processes	Fully integrated process with other IDP elements
Additional IDP Elements	Hosting Capacity	Limited, manual analysis	Basic functionality static analysis	Increasingly complex, iterative, and/or coordinated analysis	Fully integrated, continuous analysis with other IDP elements
Additional IDP Elements	Stakeholder Engagement	Limited, internally driven	Informative outreach	Proactive engagement	Incorporated

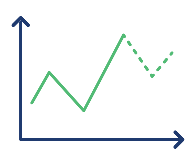
Less coordinated or integrated	**IDP Coordination & Integration**	Fully integrated

Source: Smart Electric Power Alliance, 2020.

Figure 5: Phased Progression and Requirements for Integration in IDP



Source: Smart Electric Power Alliance, 2020.



Forecasting

For distribution planning, forecasting processes traditionally focus on annual growth on the distribution system, based on historic load recorded at feeder, substation, or system peaks. These annual peaks are normalized for year-over-year weather variations, load diversity variations across levels (e.g., system, region, substation, feeder) and any abnormal system configurations or switching that may have impacted the peak loads. That data is then used to project future demand. Increased adoption of DERs on the distribution system has added new layers of complexity to the forecasting process. The industry has explored a range of methods to forecast future electric demand in systems with DERs. These include system level forecasting, DER propensity-to-adopt and multiple scenario analysis, among others (see Table 4 for more details).

Forecasting high DER adoption injects uncertainty, especially when looking at a single point in time at a single topological location. There are many unknowns when it comes to DER customer adoption rates, associated load impacts, gaps in forecasting tools and capabilities. As such, this section focuses on building incremental capabilities to capture increasingly granular data and conducting forecasting analysis to eventually account for both locational and temporal DER output. High DER adoption will require distribution engineers to adapt to evolving system constraints. In addition to assessing issues of abnormal voltage conditions at a steady state, planners will need to assess issues of voltage and frequency instability on a dynamic basis.[41] The expansion of utilities' ability to capture DER performance and growth, and have more granular visibility into the grid will be a key element in the continued evolution of integrated distribution planning and operations in a high DER future.

41 Colton Ching (2020), Hawaiian Electric Company (HECO) Integrated Grid Planning (IGP) Webinar.

Table 3: Progression of Forecasting in IDP	
Progression	**Description**
Phase 1	**Load forecasting with limited visibility:** Limited visibility, with little to no data available from the substation to the meter service point, requiring load surveys to extrapolate forecasts.
Phase 2	**Load forecasting with standard visibility:** Forecast load growth and peak demand based on load data at the substation and/or feeder level. Deterministic forecasting is generated based on static historical load data and can be adjusted based on other factors such as, weather, planned new development, anticipated load growth (system wide), circuit reconfigurations, etc.
Phase 3	**Load forecasting with increased visibility:** Locational data increasingly captured and analyzed from devices located along individual feeders, potentially including AMI data to provide more visibility throughout the distribution system. May include basic forecasts for specific DER adoption and associated load impacts including limited temporal impacts as well as multiple scenario planning.
Phase 4	**Advanced, integrated granular forecasting:** Streamlined integration of load forecasting and expected DER adoption. Includes increased coordination between load and DER forecasting processes as well as more locational data included in analysis. At this future state, planners can both see and model DER hourly output across DER types and account for temporal as well as locational DER impacts as part of the forecasting model. May include stochastic modelling of DERs based on potential variation in operating parameters.

Source: Smart Electric Power Alliance, 2020.

Phase 1: Load Forecasting with Limited Visibility

Overview: Some utilities may be starting at Phase 1, in which there may be limited data available from the distribution substation level to the meter service point. Forecasting peak demand and load growth will be limited to basic static load analysis with minimal visibility into the system at the substation levels or below. In this phase, a utility is operating under the traditional planning construct with few drivers (e.g., DER adoption, changing customer expectations and needs, minimal system constraints) indicating a need for more granular analysis and advanced forecasting. In Phase 1, few factors pose complex forecasting considerations to the distribution planner.

Key challenges and considerations: Forecasting distribution load is more difficult than system load due to the large number of substations and circuits examined, and possible switching operations in distribution systems. This challenge plagues all phases. Other main challenges at Phase 1 are due to the lack of granular data available, including:

- **Uncertainty of forecasting:** Distribution level forecasts at Phase 1 levels will be significantly more uncertain as planning horizons lengthen.[42]
- **Limited forecast of potential outcomes:** Due to lack of data availability, Phase 1 forecasting relies on a single, deterministic forecast that does not account for multiple possible outcomes brought on by system uncertainties (e.g. DER adoption).[43]

Phase 2: Load Forecasting with Standard Visibility

Overview: A larger subset of utilities are functioning in Phase 2, in which the utility may have distribution supervisory control and data acquisition (SCADA) or other forms of metering that provide visibility at the substation or feeder level, allowing them to see the aggregate load and peak demand on that portion of the system. This capability enables utilities to forecast future load growth and peak demand at the substation level, based on data recorded at previous system peaks. Forecasts are then adjusted based on factors that may include weather, planned new development, anticipated system-wide load growth, circuit reconfigurations, etc.

Key considerations and challenges: A number of utilities may be looking to transition to or are starting from Phase 2. Key considerations at this phase include:

- **Limited visibility:** Many U.S. utilities have distribution SCADA (DSCADA) which provides monitoring and

42 U.S. DOE Office of Electricity (2020), Integrated Distribution Planning Utility Practices in Hosting Capacity Analysis and Locational Value Assessment Volume IV.

43 GridLab (2019), Integrated Distribution Planning - A Path Forward, p. 9.

Accounting for DERs in Forecasting

For many utilities, load forecasting capabilities (Phase 1-2) are limited in their ability to incorporate forecasts of DER adoption. To reach an advanced, integrated granular forecasting state (Phase 4) that includes full visibility into the locational and temporal load impacts of DERs, customer or DER level metering will be needed. In addition, new tools and technological capabilities will be needed to process large amounts of temporal and locational data. Systems will require integration, and deployment of communications and sensing technology.

Other forms of forecasting and load analysis (e.g., propensity adoption models, scenario planning) can be conducted in parallel until technology and investments enable integration at Phase 4. For utilities in Phases 1 through 3, system-level forecasting, DER propensity-to-adopt, and scenario planning offer means to predict future DER adoption. These forecasting methods will likely evolve to add sophistication and locational granularity as today's software and capabilities mature. Table 4 below describes these methods.

Table 4: Additional Forecasting Methods

System-Level Forecasting (e.g., corporate or economic forecasting)	Forecasting to account for annual peak demand in a utility service territory based on previous system peaks, energy efficiency, economic growth, generation capacity and retirements, service territory demographics and other factors. System level forecasts can be "allocated" to lower levels of the system by accounting for coincidence/diversity. *Commonplace at utilities today*
DER Propensity-to-Adopt Analysis	Assesses the likelihood of technology being adopted, based on factors such as policy, economic environments, customer needs, demographics, locational economic factors (e.g. income levels) and technology maturity among other factors. Analysis can be done at varying degrees of granularity (e.g., zip code, substation, customer level). Propensity-to-adopt analysis may already be a component of system-level forecasting at the substation or zip-code level today. *Likely to be incorporated in Forecasting Phases 2-3*
Multiple Scenario Analysis	Accounts for multiple possible outcomes. In reference to DER, multiple scenario analysis can be used to analyze the effects of varying levels of DER adoption on the distribution system and variation in electric rates and tariff structures that may impact participation and energy use. Multiple scenario planning is dependent on sensitivities as inputs into analysis—which may be contingent on propensity analyses, stakeholder input/consensus, and visibility into the system. *Likely to be incorporated in Forecasting Phase 3*
Stochastic Forecasting	Stochastic forecasting builds off multiple scenario analysis to add different combinations of sensitivities to potential scenarios (e.g., variability of DER output profiles, different adoption levels, weather variability, uncertain program participation). Stochastic analysis accounts for some elements of randomness, producing multiple outputs based on a set of parameters. *Not conducted to date, likely in Phase 4*

Source: Smart Electric Power Alliance, 2020.

control capabilities along the system. These systems provide visibility and data acquisition for substations, feeder head ends and in many cases some proportion of line devices (e.g. reclosers). The real-time data from the SCADA system is typically stored in a historian for data extraction and analysis by users other than real time system operators. For some utilities, DSCADA is not distributed uniformly within the utility's service territory (i.e., only a portion of their feeders/substations are SCADA capable) and the use of the technology is not comprehensive, thus limiting system visibility.

- **Increased staff resourcing, training, and funding to build data analysis:** Phase 2 introduces an increase in the number of factors and variables incorporated into forecasts, as well as an increase in forecasting data points. Once the data is collected, organizing and consolidating the data into a form that is conducive for analysis is a time intensive process unless appropriate interfaces between analytic and historian platforms are developed.[44] Utilities will need to account for the time needed to conduct this analysis and develop expanded data management skill sets.
- **Uncertainty with lengthened planning horizons:** With standard data visibility, distribution level forecasts will be improved from Phase 1, but will continue to have uncertainty as planning horizons lengthen.[45] This is expected, as longer-term load growth and DER adoption is dependent on economic cycles, incentives and regulatory constructs.
- **Interdependencies with interconnection:** Interconnection data can help inform forecasting by providing information on planned DER connections (e.g., size, location, and type, capabilities, and settings of DERs installed). It is important to note that though utility interconnection processes collect this data, they do not always produce it in digital formats, and information is limited to location, size and type. Nameplate production associated with interconnection may also not end up representing actual production. Interconnection assumptions therefore require confirmation with actual data on DER behavior. This relates to the lack of DER output information utilities have at Phase 2.

Phase 3: Load Forecasting with Increased Visibility

Overview: At this phase, the utility can leverage data at the feeder level, providing increased visibility into the distribution system. With this expanded visibility, the utility is able to develop more locational forecasts that provide insights into needed equipment upgrades or potential operations (e.g., switching plans) that might address loading concerns. Analysis can be done at the substation and feeder levels separately, and then examined together. Phase 3's shift towards deeper visibility into the distribution network integrates top-down SCADA data from feeder breakers reconciled with bottom-up customer load from metering or AMI data to form a clearer picture of temporal and locational load. Utilities may also look to have greater monitoring and control of larger DER systems at this phase to maintain a reliable grid.

The movement to increased visibility in load forecasting is already occurring as utilities work to optimize their systems and make them more efficient. However, the rate of expansion of DERs will likely further drive the movement to Phase 3 over the next 5 to 10 years, depending on the jurisdiction.

Key considerations and challenges: Future scenarios with high DER adoption will bring about new system-wide challenges requiring more advanced forecasting and greater visibility into the system. Entering Phase 3 becomes more important as utilities look to proactively plan for or urgently address higher DER adoption in their service territory. Utilities will need to train or hire staff with increased competencies in big data management to manage increasingly complex system data. Other considerations for Phase 3 include:

- **Integrating and reconciling data between systems and teams:** Reaching Phase 3 level visibility may require rolling up AMI data and reconciling that information with DSCADA data. Forecasting efforts often are approached differently between corporate and distribution planning teams who may incorporate information from different points of the system, (e.g., AMI versus DSCADA, energy versus demand, system peak versus substation or feeder peak) for different purposes at a utility. This reconciliation process as utilities shift to Phase 3 requires consistent definitions and alignment in how they approach and interpret data, as well as integrate and align across the utility.
- **Load forecasting with DERs is getting harder:** DERs make forecasting more difficult as they increase in numbers and introduce variability on the network. Individual customers can make decisions to invest in DERs in increasingly cost-effective ways, and mass adoption has the potential to shift peaks and consumption patterns. As adoption of DERs increases, simply looking at system peak is not sufficient, as feeder

44 Smart Electric Power Alliance, Utility Sponsor Interviews (2020).

45 U.S. Department of Energy (DOE) Office of Electricity (2020), DSPx Volume IV (Forthcoming report).

peaks may not occur when there is a system peak, and feeder peaks can change depending on DERs on circuit, weather, and circuit configuration. Utilities may need to gather DER data inputs from third parties (e.g., large C&I customers, developers, site owners) and obtain schedule estimates and output data of interconnected DERs to supplement load data.

- **Ensuring data quality with tools and analysis:** As utilities shift into Phase 3, utilities are reporting that significant amounts of time and upgraded tools are needed (e.g., cloud operations for data storage) to ensure data quality. For some in regulated environments, utilities report pressures to minimize O&M costs conflicts with their needs to ensure data quality efforts.
- **Required system investments:** Forecasting with increased visibility requires access to load data deeper into the distribution network. This may require investments to the DSCADA system from end-to-end. Examples include:
  - Additional meters and measurement points
  - More communication nodes with more traffic
  - Increased data collection, storage, processing, and validation capabilities

  Utilities may also require investments in systems that feed the forecasting model. This could include upgrades in GIS mapping software or ADMS depending on where the distribution network model is maintained. Other upgrades could include the enterprise historical and/or customer and meter data management system that map customer level meter data to individual distribution transformers, feeders and substations.
- **Technology and implementation cycles may require long lead times:** Separate from the commercial availability of tools to enable Phase 3, utilities should consider the time it takes to integrate new tools and reconcile data. For example, the process to integrate data sources and fully implement an advanced power flow tool typically takes at least 3 years at a utility today.[46]
- **Data and cyber security:** The security of the connection and the data is of increasing importance, similar to substation automation and other SCADA technologies.

Phase 4: Advanced, Fully Integrated Granular Forecasting

Overview: While Phases 1-3 in forecasting are more known to the industry today, Phase 4 represents a future state that continues to evolve and will be influenced by technology advancements and customer adoption behaviors. Today's Phase 4 envisions utilities developing capabilities to collect real-time customer data, drilling beyond hourly load output to see and predict customers' energy usage and hourly DER output. This could also include having visibility and capabilities to dispatch locally stored energy. Based on technology advancements (e.g., DER output data, advanced inverter data), weather and an increased ability to predict customer behaviors, Phase 4 envisions capabilities to predict temporal and locational DER impacts and forecast DER adoption from the bottom-up based on more granular and informed data.

At this phase, other forecasting methods (described in Table 4) would be integrated with load forecasting, leveraging actual DER output information, as opposed to conducted separately and in parallel. Granular data collected in Phase 4 could enable predictive analytics to anticipate both collective and specific customer behavior with DERs, taking into account their interactive effects. Phase 4 of forecasting remains very much an aspirational future state, dependent on the industry's ability to overcome technological and managerial hurdles, detailed below.

Key considerations and challenges: Phase 4 stands as a more theoretical future state the industry may reach as analytics and technology capabilities continue to mature. As a wider number of feeders along the distribution system experience constraints due to DER adoption, there will be an increased need to build capabilities towards Phase 4. Forecasting at Phase 4 levels will require big data management, advanced analytics, as well as tight integration of planning and operational systems. The ability to have visibility and predict DER performance and customer behavior will require investments beyond system-level investments laid out in Phase 3. Advanced forecasting tools (e.g., statistical analytic tools) and software capabilities will need to reach commercially mature stages. Investments in data storage solutions (e.g., data lakes) will also be required. Beyond tools and system investments, utilities will need to invest in acquiring or building internal analytic competencies. Utilities at Phase 4 may see greater automation and greater big data management expertise to manage the increasingly complex system data.

46 Smart Electric Power Alliance (2020), Utility Sponsor Interviews.

At this future phase, a few additional considerations may include:

- **Control and visibility along the system:** A utility might have a mixture of decentralized control devices for smaller systems alongside a centralized control system to help operate the system. While the level of controllability relates back to the determined operating models of the future, it is essential for planning purposes to know what settings have been set, and where.
- **DER ownership, control, and/or visibility:** This future state may include a significant number of behind-the-meter assets that could impact load. How a utility will operate a growing number of assets they do not own, or that may not be controllable or dispatchable by the utility will bring another layer of challenges in analyzing and predicting how they may impact the system further out (e.g., volt/var control).
- **Analyzing interactive DER impacts:** Beyond gaining greater visibility into DER output, Phase 4 may bring increasingly complex DER interactions to predict. For example, customers may adopt multiple DERs at a site (e.g., solar PV, battery storage, smart thermostat, and EVs adopted within a home), and those interactive effects of DERs, as well as customers' behaviors, may in aggregate have material impact on forecasting load.
- **Data sharing and cyber security:** Data and cyber security becomes critically important as utilities transition from Phase 3 to 4. Reaching this phase will require greater bidirectional information flow between the utility and DER developers/owners. Phase 4 brings more granular data that may include customer personally identifiable information, customer-specific DER performance, data from customer resources outside of the utility's circle of trust, and other third-party data sources. Each of these bring new and unique challenges for ensuring the privacy of customer data and sensitive utility asset data.

Sourcing Solutions for Grid Needs

A key element defining many IDPs today is the increased consideration of DERs and other non-traditional solutions[47] to help manage constraints along the transmission and distribution grid. Advancements in technologies have expanded the capabilities and potential for solutions such as microgrids, energy storage, and demand flexibility programs, among others, to provide services to the grid. The most common approach for examining non-traditional solutions today is NWAs, which serve as an avenue for examining DERs and other non-traditional solutions to avoid or defer infrastructure upgrades.

Table 6 lays out the phased progression for sourcing solutions for grid needs, starting with piloting and demonstration projects to build a deeper understanding of DERs as grid solutions, and transitioning towards more integrated processes for evaluating and sourcing non-traditional solutions in planning processes (e.g. NWA screening processes). Sourcing NWAs may include procurement processes, customer programs, and pricing tariffs. Many efforts today have focused on procurement processes (e.g., New York's REV Connect[48]), but interest in leveraging existing customer programs (e.g., Xcel Energy) and exploring pricing tariffs (e.g., Hawaii) is growing. As utilities and stakeholders invest in advanced tools and grid infrastructure, the future may reach a future Phase 4 in sourcing grid solutions, in which DERs are streamlined and leveraged along the grid based on their temporal and locational value. Still, challenges exist at almost every phase of advancement. These considerations are discussed below.

47 While DERs are the main focus for many non-traditional solutions, other advanced technologies may not fit the definition but can be included for consideration. This may include: energy waste reduction (EWR), large front-of-the-meter utility-owned systems, electric vehicles, grid software and controls, etc.

48 NY REV Connect, Non-Wires Alternatives, accessed 7.14.2020, https://nyrevconnect.com/non-wires-alternatives/.

Locational Value Analysis—Activities and Challenges To Date

Market mechanisms, such as evaluation processes around NWA procurement and solicitations, allow the utility to source DERs through an open and competitive marketplace. Currently the most advanced efforts to facilitate sourcing DERs for grid needs (or to address locational constraints) involve locational and temporal value frameworks and analysis. These efforts are seen as a key step to informing DER optimization. Approaches to establishing such locational and temporal value market mechanisms are still in their earlier stages due to limited capabilities and methodologies existing to date, but will play a key role along the progression of DER sourcing for grid needs in the coming years. Activities have taken place in a few states centering on a framework for evaluating grid resources based on where DERs are located. California and New York developed value stacks to assess locational value across varying categories, including: distribution, transmission, generation, environmental, and societal.

Utilities have scaled back implementation efforts due to the high complexity and costs associated with conducting analysis. These efforts are still developing, but early learnings point to important challenges to consider as states and utilities move to incorporate similar efforts in more advanced phases of IDP. Key challenges today include:

- **Lack of consensus on locational value analysis methodologies:** The calculation and inclusion of different value components vary by jurisdiction, regulatory compliance mandates, existing service markets, and utility definitions.[49] A range of BCA frameworks also exists, ranging from purely utility-system focused costs and benefits, to other frameworks that expand into customer, societal, and environmental value components.
- **Complexity of analysis:** Utilities expressed challenges in properly assessing and assigning a numerical value to a location when taking into consideration the many mechanisms and various methods a utility could use to design and operate distribution systems. Many value categories may be more qualitative and difficult to quantify. Determining what is included in an assessment and how to quantify some categories remains a challenge in the industry today.[50] For some of these components, stakeholders and utilities are unclear on how to quantify some value components, and for qualitative components, how to use those assessments in conjunction with quantitative analyses.[51]
- **Without situational awareness via devices and analytics, locational value cannot go far:** Early learnings in California indicate that analytic capabilities are foundational to understanding where DERs can cost-effectively interconnect.[52] The accuracy of load forecasting at a phase or circuit level may have high levels of uncertainty as discussed in Forecasting. If confidence levels in load forecasts are low (e.g., Phase 1 or 2 of Forecasting), then the accuracy and confidence of the associated locational value derived will be similarly low.

Table 5: Locational Value Assessments for Solution Sourcing Efforts

State	Name	Overview
California	Distribution Investment Deferral Framework (DIDF)	Framework for evaluating opportunities for DERs to cost-effectively defer traditional investments identified by utilities to mitigate forecasted constraints on the distribution system.[53]
New York	Value of DER (VDER) Value Stack	Established a VDER tariff where DERs subject to the "Value Stack" receive compensation for the energy they inject into the system for a set of values calculated based on the utility costs they offset.[54]

Source: Smart Electric Power Alliance, 2020.

49 U.S. DOE Office of Electricity (2018), Integrated Distribution Planning: Utility Practices in Hosting Capacity Analysis and Locational Value Assessment, p. 23.

50 Smart Electric Power Alliance (2020), Utility Sponsor Interviews.

51 Smart Electric Power Alliance (2020), Renovate Initiative: Developing a Comprehensive Benefit-Cost Analysis Framework: the Rhode Island Experience.

52 GridWorks (2019), DRP Retrospective Chapter Three: New York's REV and California's DRP.

53 California Public Utilities Commission (CPUC) (2018), Decision 19-02-004 Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769, p. 27.

54 New York Public Service Commission (2019), Case 15-E-0751 In the Matter of the Value of Distributed Energy Resources Whitepaper Regarding Future Value Stack Compensation Including for Avoided Distribution Costs, p. 2.

NWAs: A Path (But Not the Only Path) Towards Integrating DERs

Many in the industry see NWAs as an opportunity to seek cost-effective, non-traditional solutions (e.g., DERs) in the planning process. To date, the process of evaluating NWAs has provided concrete opportunities for determining and leveraging the locational benefits of DERs. However, challenges from existing NWA efforts indicate that NWAs may be one path—but not the only path—towards integrating DERs and other non-traditional solutions. These considerations are highlighted below and discussed further in later phases of the framework outlined in Table 6.

Key Opportunities:

- **Flexibility amid uncertainty of load growth:** Deploying DERs as a NWA can offer a flexible solution to deploy incrementally and adjust as forecasts and system conditions change.[55]
- **Opportunity for leveraging locational value of DERs:** Utilities can quantify the economic locational benefits of DERs through the value of the avoided or deferred infrastructure investment.

Key Challenges:

Utilities are finding less success with NWAs, with fewer projects making it through screening and evaluation processes.[56] This may be due to:

- **Strict performance criteria to reduce system risk:** Concerns over customer DERs not performing when expected are typically addressed through strict performance criteria for NWAs. These requirements can prove challenging for solution providers to meet.
- **Challenges with competitive NWA solicitation processes:** Competitive procurement processes for NWAs in some states are experiencing obstacles in procuring DERs, with solution providers facing challenges in meeting technical and performance requirements. In some of these regions, bidders are expressing fatigue through the process with respect to costs and resources.
- **Cost effectiveness:** Some higher-cost solutions (e.g., large battery storage systems) are yielding low benefit-cost ratios. This is likely especially the case for shorter deferral projects.

Additionally, the industry still faces significant challenges in determining locational value. Limited guidance and proven practices exist that show how to conduct benefit cost analysis (BCA) for NWAs, and more broadly for determining locational value of DERs.

With the opportunities and challenges considered above, the scope of the discussion of integrating DERs and other non-traditional solutions into the planning process is broadened to discussing sourcing solutions, inclusive of- but not limited to- current NWA practices.

Table 6: Progression of Sourcing Solutions for Grid Services in IDP

Progression	Description
Phase 1	**DERs not considered as solution for addressing distribution system constraints/needs.**
Phase 2	**Piloting:** Explore use of DERs and other non-traditional solutions for new business models, procurement, contracting, and technology performance to address distribution system constraints.
Phase 3	**Evaluation of DERs and other non-traditional solutions are integrated into the IDP process:** Includes incorporating an evaluation or screening process to examine the ability of DERs to avoid or defer infrastructure investments along the grid. Also includes mechanisms to source DERs for grid services.
Phase 4	**Streamlined DER solutions sourcing based on Locational and Temporal Value:** Leveraging both pricing and system constraint data, DERs are further integrated onto the distribution system based on their locational and temporal benefits. The sourcing method could include procurements, pricing tariffs, and streamlined strategies via customer programs. Reaching Phase 4 requires confidence in predicting customer behavior and DER performance to meet system reliability requirements, as well as the ability to control or reliably call on DERs such as storage for volt/var or grid power quality.

Source: Smart Electric Power Alliance, 2020.

55 E4TheFuture, PLMA, and Smart Electric Power Alliance (2018), Non-Wires Alternatives Case Studies from Leading U.S. Projects, p. 9.
56 Greentech Media (2019), Few Opportunities, No Contracts: Slow Progress for Non-Wires Alternatives in California.

Phase 1: DERs Not Considered for Addressing Distribution System Constraints/Needs

Overview: Many utilities today are starting in Phase 1, in which traditional distribution planning identifies an upcoming constraint or risk along the system, often based on accounting for forecasted load growth. The utility then examines and proposes traditional solutions (i.e., poles, wires, substation upgrades) to alleviate these grid constraints.

Utilities in Phase 1 may not see many short- to medium-term constraints coming up on their system, or such DER-related constraints may be localized to a handful of feeders. In some cases, utilities may not anticipate significant load growth or may even see declining load on their system. Circumstances and conditions along the system will vary utility to utility.

Key considerations and challenges: At this earlier stage, the utility may need to overcome internal cultural challenges, as distribution engineers adjust to the idea of trusting DERs to meet system needs. The existing regulatory environment may serve as an obstacle. Existing policies at this phase may prevent tariff and compensation structures, or fail to enforce contractual requirements for third-party and customer DER performance. Other DER demonstration or pilot efforts taking place outside of planning efforts may help utilities better understand the capabilities and performance of DERs in meeting the needs of the grid.

Additionally, as mentioned in Forecasting, DER technology adoption brings the potential for quick and significant changes to system conditions in ways that are challenging to predict with today's tools. It may be necessary for utilities to begin testing and building competencies with other DER technologies to prepare and plan for an uncertain DER future and consequential varying system load.

Phase 2: Piloting and Demonstration Projects

Overview: The next phase as utilities begin to explore the capabilities and value of DERs along the grid is to pilot DERs and explore NWAs. In this phase, utilities have the opportunity to enhance internal capabilities and tools and can evaluate the capabilities of DERs in alleviating system constraints. The process of examining benefits and costs, sourcing solutions, implementing, and evaluating results of a NWA pilot helps to build up internal systems, processes, and knowledge at the utility.

While some utilities may already have mature demand-side management programs used to help defer distribution investments (e.g., geo-targeting energy efficiency programs), Phase 2 piloting and demonstration focuses on projects that allow the utility to test emerging technologies and business models associated with DERs. A number of utilities have begun piloting or examining opportunities today, with more pilots likely to emerge over the next 5 years.

Key considerations and challenges: Phase 2 may take place as utilities begin identifying upcoming system constraints or anticipated load growth, and look to learn more about DER performance along the grid. Considerations at this phase include:

- **Resource intensive analysis for identifying NWA opportunities:** Learnings from utilities conducting NWA analysis today have found the process can be highly time consuming and manual. In the case of Xcel Energy Minnesota, for each identified system constraint under consideration, planners pulled peak load curves for feeders and substation transformers, forecasted these curves out to the desired year, and tailored and added different DER resources into the analysis to find appropriate resources and sizing.[57] If multiple constraints are under consideration, conducting this analysis without key system integrations is a laborious and time-intensive manual process.
- **Disparate systems and implementing customized solutions:** The process of implementing and deploying NWA solutions may require different systems to manage and operate DERs of different types. A number of NWA solutions may require customized, one-off solutions, and significant resources to provide oversight and management.[58]
- **Long lead times for implementing:** Early learnings from existing NWA case studies highlight the need to build in enough time for implementation. The average lead time has ranged from 18 to 60 months depending on project size.[59] Long lead times for some NWA projects may render them unsuitable for addressing near-term issues.
- **Regulatory framework and funding for research and development (R&D):** For regulated utilities, their ability to develop pilot and demonstration projects at this phase may depend on the level of support from commissions. Some commissions have issued orders

57 Xcel Energy (2020), Integrated Distribution Plan, p. 98.

58 Xcel Energy (2020), Integrated Distribution Plan, p. 90.

59 Con Edison (2018), Con Edison's Non-Wires Solutions, p. 5; Presented to MEDSIS NWA Working Group.

allowing more R&D funding or innovation funds, but this is not yet widespread. More broadly, regulatory frameworks may need to evolve to enable utilities to conduct more pilots and demonstrations of new technologies, operating models, and processes.

Phase 3: Evaluation of DERs and Non-traditional Solutions into the IDP Process

Overview: At this phase, evaluating DERs and other non-traditional solutions is more integrated into the IDP process. Utilities may include screening processes to evaluate and promote DER deployment. The process of screening and evaluating DERs at Phase 3 requires mechanisms to evaluate costs and benefits of leveraging DERs for grid services. Utilities may also form NWA groups incorporating cross-functional staff members (e.g., distribution planners, engineers, emerging technology, and customer program).

Earliest examples of Phase 3 activities can be seen in New York and California, where utilities have integrated screening and evaluation processes to examine NWA opportunities. Efforts in these states also include processes to evaluate the benefits and costs of a proposed NWA compared to the traditional solution. In Hawaii, their IGP process considers traditional capital grid projects and non-traditional market based solutions (including targeted DER programs, non-wires alternatives from competitive sourcing methods, and pricing tariffs).[60] Depending on the goals, objectives, and needs of the utility and its stakeholders, this phase may require stakeholder engagement to inform the screening process and integration into the planning process.

Key considerations and challenges: Phase 3 requires a deeper industry understanding or consensus on conducting BCA analysis and other forms of locational value assessments between the utility and stakeholders. The utility may be experiencing more system constraints and fluctuations along the grid and may seek to evaluate more cost-effective DER solutions. Only a few states (e.g., New York) have entered into Phase 3. More utilities will likely reach Phase 3 maturity over the next decade.

Additional to the key considerations and challenges discussed in Phase 2, Phase 3 enters into a more enhanced evaluation and sourcing process for DERs, including a new set of challenges detailed below.

- **Few NWA projects make it through screening and evaluation processes:** After further filtering for today's technology capabilities and factoring in cost-effectiveness, utilities are finding a very small number of projects (in some cases close to or less than 1%) make it to the finish line. Utilities have noted that after identifying the right type of system constraints (typically capacity constraints), only a subset were technically addressable. Additionally, strict performance criteria and cost-effectiveness considerations may be at play. Increasing definition and demonstration of value streams from DERs may enable improved screening approaches that will lead to greater DER adoption to address distribution constraints.
- **Concerns and risk of DERs not meeting performance criteria:** Distribution engineers, focused on their core objective of operating a safe and reliable grid, often express reluctance to deploy DERs for key grid services due to concerns around DERs not performing when expected. DERs that depend on customer action and behavior adds another layer of reluctance. Some utilities address this concern through strict performance criteria, contracts with solution providers ensuring performance, and development of contingency plans in the cases of non-performance.
- **Challenges with competitive NWA solicitation processes:** Competitive procurement processes for NWAs in some states are facing similar challenges when procuring DERs. Stakeholders in some states with competitive procurement processes face challenges in meeting the technical and performance requirements for participation that the utility feels it must impose to ensure grid reliability. Less established bidders may become fatigued by the resources and costs required to participate, compounded by the uncertainty in winning opportunities.
- **Benefit-cost analysis and the challenges of determining locational value:** The industry today has limited guidance and proven practices on how to conduct BCA analysis for NWAs, and more broadly for determining locational value of DERs. In the case of NWAs, determining both the initial and ongoing costs, as well as the expected lifetime of the DER and its benefits, are key to determining cost-effectiveness. The more qualitative benefits (e.g., societal benefits, customer empowerment and choice, demand flexibility) are also harder to quantify and measure.

Phase 4: Streamlined DER Sourcing to Meet Grid Constraints

Overview: In Phase 4, utilities leverage advanced analytics and granular pricing and system constraint data to derive locational and temporal values of high accuracy. This enables utilities and stakeholders to effectively

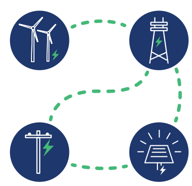
60 Smart Electric Power Alliance (2020), Interview with Colton Ching, Hawaiian Electric Power Company.

identify where DERs can be optimized along the grid within core planning processes, alongside other solutions. Sourcing methods may include procurement, pricing tariffs, and streamlined engagement with customer DERs through programs. Reaching Phase 4 requires enhanced computational capabilities, confidence in predicting customer behavior and DER performance to meet system reliability requirements, as well as the ability to control or reliably call on DERs.

Key considerations and challenges: Reaching Phase 4 requires development of data capabilities, tools, and other technologies to predict customer behavior and DER hourly (or sub-hourly) performance. The IDP process likely requires confidence in predicting customer behavior and DER performance to meet system reliability requirements. This phase has interdependencies with Forecasting capabilities and other IDP elements. Early adopters are developing the technologies and capabilities to reach this phase, and development is expected to continue throughout the coming decade.

Phase 4 stands as a more aspirational future state, which will require overcoming a number of significant challenges laid out in Phase 3. This includes further streamlining of the screening and evaluation processes to reduce resource efforts and intensity, developing clear methods and tools to accurately determine locational and temporal value, reducing lead times for obtaining DER services to the grid, and overcoming concerns of performance risk or increasing DER solution provider contracting sophistication.

Core challenges center around the need to develop the visibility, as well as analytic tools and capabilities, to confidently predict customer behavior and DER performance, calculate locational and temporal values for hundreds of thousands of nodes or segments on a utility's distribution system, as well as dispatch and/or control DERs to help manage constraints along the grid in a more streamlined and integrated manner. Regulatory constructs will also need to evolve to enable utilities to transition from existing revenue models to ones that allow or incentivize the utility to adopt competitive market provided solutions for grid needs.



Transmission, Distribution, and Generation Integration

A key feature of IDP is the increased coordination and potential integration between transmission, distribution, and generation[61] planning. This occurs today, to varying degrees, as integrated resource planning (IRP) processes increasingly consider the adoption of DERs by customers and 3rd parties. Table 7 lays out the potential phased progression of integrated transmission, distribution, and generation planning processes, starting from siloed planning processes and transitioning to increasingly iterative and coordinated efforts.

The type of utility, (e.g., investor-owned vs. cooperative or public power) and whether it is vertically integrated or participating in a restructured market may limit the ability for utilities to progress along the continuum laid out in Table 7. For example, in some restructured markets, a utility is responsible for distribution planning and cannot own generation. In these cases, the Regional Transmission Organization (RTO) / Independent System Operator (ISO) separately handles transmission planning or establishes market mechanisms for resource planning. Integration of distribution and generation planning may be most relevant to vertically-integrated utilities. TDG integration encounters a number of regulatory and jurisdictional challenges that fall outside scope of this report, but these challenges should be considered within the context of what is feasible for each utility's IDP.

Phase 1: Siloed Planning Processes

Overview: In Phase 1, distribution planning is largely done separate from other planning processes such as transmission planning and IRP processes. Limited communication between these groups is required for the grid to operate reliably, with distribution planning focused predominantly on planning for peak demand, load growth and declines, as well as identifying aging assets or needed replacements. At this phase, DER impacts are small enough that they do not warrant dedicated attention in transmission and bulk power system planning.

61 "Generation" applies to vertically integrated companies, not restructured companies and encompasses both supply-side and demand side resources.

Table 7: Progression of Transmission, Distribution, Generation Integration in IDP	
Progression	**Description**
Phase 1	**Siloed Planning Processes:** Distribution planning done separate from other planning processes (e.g., transmission planning, IRP) and focused on planning for load growth.
Phase 2	**Annual Iterative Approach:** Linking transmission, distribution and generation planning (as applicable). DERs at this stage do not pose material risk to transmission and bulk system operations. Distribution planners share their static load analysis and limited DER forecasting with transmission planners and compare with existing IRPs.
Phase 3	**Increasingly Iterative Approach:** Linking transmission, distribution and generation planning. Net load characteristics on distribution systems begin to impact transmission and bulk system operations. DER growth patterns, timing and net load shape assumptions and plans shared iteratively.
Phase 4	**Continuous and co-optimized planning processes:** Integration between distribution, transmission and generation planning. Net load characteristics with DERs on distribution systems can significantly impact transmission and bulk system operations, requiring coupled, iterative analysis of distribution and transmission planning with DERs, and incorporation into integrated resource planning processes.

Source: Smart Electric Power Alliance, 2020.

Phase 2: Annual Iterative Approach

Overview: Phase 2 brings some coordination between transmission and distribution planning, as applicable. DERs at this stage do not pose a significant impact to transmission and bulk system operations. Any issues that do arise are likely handled on a case by case basis. Distribution planners at this stage typically share their static load analysis (e.g., peak load projections, load relocation, capacity needs) and limited DER forecasting as inputs for transmission planning processes. Distribution planners may also compare analysis with existing IRPs (as applicable). These groups may interact with one another more frequently as needs arise (e.g., identified need for additional electrical supply to the distribution system, interconnection requests for new projects that may affect the system).

Key considerations and challenges: At this stage, DERs may still have minimal impact to the transmission and bulk power system. Coordination on an annual basis is already taking place at a number of utilities, and others may look to begin annual coordination over the coming years. Considerations arising at Phase 2 include:

- **Alignment of inputs in multiple planning models:** The industry will incrementally progress along Phases 1-3 for some time, and thus work under different planning models. Until new planning tools emerge that integrate these planning processes, utilities will need to ensure inputs are aligned. Alternatively, utilities could develop integrations across the component tools (e.g. forecasting, power flow analysis, and BCA tools). Aligning the inputs and determining how planners incorporate distribution level information to transmission is something the industry will need to work through, and will provide the basis for integrations or overall integrated tools. To date, processes to tackle this have included increasing iteration and scenario analysis.
- **Potential interconnection challenges with distribution and transmission studies:** 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.
- **IRP versus distribution planning:** For vertically integrated utilities looking to integrate generation and distribution planning, IRP planning cycles are much longer (10-20 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.

Phase 3: Increasingly Iterative Approach

Overview: Phase 3 represents an increasingly iterative approach between transmission, distribution, and generation planners. Net load characteristics on the distribution system begin to impact transmission and bulk system operations, and thus warrant greater coordination between planning groups within a vertically-integrated utility, as well as coordination between distribution planners and RTO/ISO planners in restructured markets. There will be a growing need for greater visibility into the location and capabilities of DERs across groups. In RTOs/ISOs, greater visibility is needed so that the wholesale market can account for DERs and avoid overbuilding. Information shared between these teams may include DER growth patterns, timing of DER performance and adoption, as well as net load shape assumptions and plans. Planners may begin to explore iterative approaches over the next decade, depending on the conditions of the systems.

Key considerations and challenges: The need to increase communication between different planning groups will depend on the system conditions on both the distribution and transmission ends. DER adoption may have reached higher thresholds, with a percentage of substations or pockets along the system experiencing challenges. In some cases, the transmission side may be a more limiting factor requiring upgrades or further coordination to manage constraints. Phase 3 may begin to force new regulatory decisions on market rules (e.g., FERC 841), operating models, and authority among different parties (e.g., FERC/NERC, states, utilities).

- **DER ownership models and visibility:** Visibility into DERs will be required in the future regardless of ownership models. A core question for a number of utilities when examining the future of planning is how to reliably plan and operate in coordination with non-utility-owned resources as the industry experiences DER adoption at high levels.
- **Limitations of current planning tools:** Today's planning processes and tools were designed to support bulk power supply, with the assumption that it serves distribution load and optimizes for cost and reliability. As DER adoption reaches higher thresholds, these traditional utility planning tools and methodologies will not befit changes in distribution load and the level of granularity, forecasting, and integration required between planning groups. Utilities will need new advanced planning tools and grid investments to enable greater iteration and streamlining between transmission, distribution and generation at this phase.[62]
- **Accounting for expanded DER capabilities and grid services in planning and operations:** Distribution planners typically view DERs as a reduction in load. As the capabilities of DERs, such as energy storage continue to expand and evolve, how DERs are accounted for in transmission, distribution, and generation planning processes (e.g., increases, shifts, reductions in load) will need to be taken into further consideration.
- **Greater needs for granular data collection, analysis, and sharing to integrate with forecasting and other IDP elements:** The ability to increasingly integrate processes across planning groups is dependent on advancement in more granular data and analysis at the distribution level. Transmission and generation planning will need DER forecasts aggregated to relevant transmission system nodes to understand the locations where DERs will be adopted. Eventually planners will need to account for future performance and interactions of those systems (i.e., in Phase 4). Dependencies exist at this phase with other IDP elements (e.g., forecasting).
- **DER participation and alignment in retail and wholesale markets:** Growing opportunity may exist for DERs to contribute to the reliability of the power system. However, providing services beyond the distribution level will require coordination and visibility between distribution utilities and RTOs/ISOs on where DERs are located, and how they are operated.[63] This may require RTOs and ISOs to work with utilities or aggregators to coordinate operations, expand communication capabilities, and manage operational priorities when conflicts of interests arise among transmission, distribution, and generation.
- **Clear Requirements for DER Reporting:** Integration of transmission, distribution and generation planning requires that data collected at the DER-level can be used in distribution and transmission planning. Clear data requirements help integrate these processes.

Phase 4: Continuous Co-Optimized Planning Process

Overview: Phase 4 reaches the future state with operational real-time processes for co-optimized planning between transmission, distribution, and generation planners. Net load characteristics with DERs on the distribution system can significantly impact transmission

62 Xcel Energy (2020), Integrated Distribution Plan, p. 83.

63 MidAtlantic Distributed Resource Initiative (MADRI) (2019), Integrated Distribution Planning for Electric Utilities: Guidance for Public Utility Commissions, p. 13.

and bulk system operations, which requires simultaneous analysis of distribution and transmission planning with DERs; and incorporation into IRP processes.

Reaching a co-optimized planning process between transmission, distribution, and generation planners may be much further out on the horizon, and dependent on the development of new integrated planning tools or integrations between planning tool components, as well as expanded operational capabilities along the grid.

Key considerations and challenges: A co-optimized and continuous planning process is dependent on the progression of utilities to reach later phases across other IDP elements (e.g., load forecasting, interconnection, etc.). Challenges and considerations at Phase 4 will also vary depending on the type of utility and their regulatory and market environment. At Phase 4, the complexity of planning and operating the distribution system is exponentially higher, and reaching this phase will further force new regulatory decisions on market rules, operating models, and authority among different parties. Another key challenge is the lack of viable tools integrating transmission, distribution, and generation planning. Information, rules, regulatory mandates, and technology capabilities will likely have evolved to enable Phase 4 in the future.

Interconnection—Information Integration

The interconnection process typically includes a safety review of prospective grid-connected resources, and a contract to compensate for the services provided. Data from interconnection requests provide critical information to utilities (e.g., where customers are looking or have looked to interconnect DERs, what type of resources are interconnecting, and the size of systems). In today's planning process, these data are often underutilized. As DER adoption increases, enhancing the interconnection process to effectively capture and utilize this information will become increasingly important to distribution planners, and can enable future IDP processes.

Utilities are already beginning to see growing complexity as they receive increasing requests for varying sizes and types of DERs, and in some cases requests to interconnect paired systems with interactive effects. In some states, including California, utilities are further streamlining their interconnection processes to integrate with hosting capacity. Efforts to streamline and coordinate

Table 8: Progression of Interconnection in relation to IDP

Progression	Description
Phase 1	**Manual interconnection process:** Within the context of low DER adoption, interconnection applications are collected and processed through a static technical screening process.
Phase 2	**Increasingly digitized and streamlined interconnection process:** With growing DER adoption, expedited processes and greater digitization are needed for smaller capacity systems to meet the growing interconnection queue demand and improve efficiency. Interconnection processes expand to integrate different technologies and their unique circumstances (e.g., energy storage, solar + storage, community solar).
Phase 3	**Increasingly automated and streamlined interconnection process, coordinated with other IDP processes:** A high DER penetration scenario necessitates an enhanced screening process. At this phase, it may be tied or more coordinated with hosting capacity to assist customers and other stakeholders in adopting DERs in areas that most support the grid.
Phase 4	**Fully integrated process with other IDP elements:** In this future state, interconnection may no longer exist in the form of streamlined studies but may function as a highly-coordinated function within a fully streamlined IDP process. Locational benefit analysis (informed by hosting capacity) may play a larger role at this phase to actively direct locational and temporal specific deployment of DERs to maximize grid support and minimize the system impacts of DERs.

Source: Smart Electric Power Alliance, 2020.

interconnection with other processes of IDP may become more highly coordinated and integrated at later phases.

Investments in digitization, automation, data storage, and analytic tools can help utilities better utilize information coming from interconnection studies to inform the planning process. Table 8 explores how interconnection may evolve within the IDP process.

Phase 1: Manual Interconnection Process

Overview: In this phase, the utility's interconnection process is largely a manual one, conducted and processed by their engineers predominantly to track and monitor interconnections on the grid. Engineers also evaluate any implications of interconnecting where customers or third parties are looking to develop. This phase includes the traditional practice of collecting and processing interconnection applications through a static technical screening process.

Key considerations and challenges:

- **Manual Processes:** There is a growing recognition nationally by utilities, regulators, and stakeholders alike that improvements to typically manual interconnection processes are needed to meet customers' expectations and improve workflow. As the number of requests and diversity of DER requests grows, the manual processes in Phase 1 may become increasingly overwhelmed, resulting in increased interconnection processing times and a growing interconnection queue. Utilities in Phase 1 should consider transitioning to Phase 2 before this occurs.
- **Staffing Levels:** Utilities at Phase 1 likely have limited staff dedicated to DER interconnection issues and limited documentation on their internal interconnection processes.

Phase 2: Increasingly Digitized and Streamlined Interconnection Process

Overview: As DER adoption increases, Phase 2 may include expedited processes and greater digitization to meet the growing interconnection queue demand. In this case, utilities may implement some online and automated processes at key pain point areas such as the application process. Automation also provides efficiency in workflow. Utilities in Phase 2 are generally focused on reducing the overall interconnection timelines from application through approval to operate. Interconnection processes may also expand to recognize and integrate different technologies and programs (e.g., energy storage, solar + storage, community solar). Efforts at this phase may also align with IEEE Standard 1547-2018, California Rule 21, and Hawaii 14-H interconnection requirements.[64] Interconnection processes may become more closely integrated with other customer loading and service requests.

Key considerations and challenges: Utilities may have various reasons for justifying a shift to Phase 2 interconnection processes, including increased DER adoption that leads to burdensome manual work. The efficiency and streamlining of processes that accompanies digitization can create a business case for transitioning to Phase 2 well before reaching a specific DER penetration threshold. Other considerations include:

- **Processing new DERs and larger systems:** Interconnection processes will need to address new, evolving technologies (e.g., battery storage systems, microgrids, vehicle-to-grid). For larger or more complex interconnections, modeling and study complexity will inhibit fast tracking through a streamlined interconnection process.
- **Lack of readily available data:** Data at this stage is not always available in digital formats. This is a constraint as utilities shift into Phase 2 levels, and is interrelated with forecasting.
- **Expanding distribution engineer skill sets for large DERs:** Utility staff will need to develop a greater understanding of transient stability analysis, including both frequency and voltages, for large-scale DER resources or complex combinations of DER technologies.

Phase 3: Fully Automated and Streamlined Interconnection Process, Coordinated with other IDP Processes

Overview: Phase 3 builds off increased digitization in Phase 2 to reach a largely automated and streamlined interconnection process. With significantly high DER adoption at this phase, further enhancing the screening process to expedite approval processes is necessary. This could include established screens, typically referred to as level 0 or level 1 screens that seek to expedite the review and approval of interconnection applications that pass criteria to not warrant further investigation and review. In some cases, Phase 3 may coordinate interconnection with other IDP processes to automate analysis of impacts of proposed DER interconnections. Utilities may include DER interconnection assessments in multi-year planning to account for any needed grid upgrades.

64 These standards define new technical capabilities that many jurisdictions will require and validation of these capabilities will occur at interconnection. These technical capabilities make it easier to configure and enroll DER at interconnection. The data produced regarding these functional capabilities (monitoring and control) are leveraged in later phases of forecasting, sourcing solutions for grid needs, and TDG integration. The enrollment, validation of conformance, and initial configuration of these DERs occurs at interconnection.

Some states, such as California, are taking steps to streamline interconnection processes and integrate them with hosting capacity. These efforts are in their early stages of implementation and have not yielded many lessons learned. The need to integrate interconnection with other IDP elements (i.e., hosting capacity) links back to the goals and objectives that utilities and its stakeholders are seeking to achieve.

Key considerations and challenges: Depending on the volume and size of projects interconnecting, a utility may be driven more towards automation along Phase 3. Similar to Phase 2, utilities may also determine a need to shift to Phase 3 based on costs and level of effort required to process the increasing number of requests to interconnect systems.

While the volume of interconnection requests dictates the transition to Phase 3, the type of requests and their location on the system are also important. Utilities seeing increased numbers of large systems looking to interconnect (e.g. community solar or large customer interconnection) will likely transition to Phase 3 earlier than utilities seeing primarily residential interconnection requests. Other considerations include:

- **Approach to interconnection requests violating planning criteria:** Utilities and stakeholders will have to determine at these later phases how to approach and respond to requests to interconnect DERs that may cause thermal or voltage violations. These approaches will vary by utility and regulatory environment. However, as utilities advance to later phases in the IDP process, they may consider other opportunities when interconnecting systems (e.g., NWAs, dynamic hosting capacity, etc.).
- **New tools, modeling capabilities, and challenges:** Incorporating new revisions to industry technical standards will require new modeling capabilities for the utility system. The 2018 IEEE 1547 revisions will require new modeling capabilities for inverter advanced functions.[65] Phase 3 also faces challenges in the preparation of grid models and limitations in existing load data when performing automated analysis. Finding ways to validate and check for consistency in the data, while minimizing staff effort to review data, may be a challenge at this phase with limited automation tools available to date.
- **Potential dependencies and limitations when coordinated with hosting capacity analysis:** Utilities can potentially further integrate and streamline interconnection processes with hosting capacity analysis. This could apply when utilities publicly share hosting capacity analysis data to customers and DER developers to help identify viable locations to interconnect. However, as is discussed in the section below, (see Hosting Capacity) the accuracy and reliability of HCA is highly dependent on the approach and level of investment. For these reasons, HCA has been advised to serve not as a substitute for a comprehensive interconnection study, but as more of a functional tool to inform from the 10,000 foot view.[66]

Phase 4: Fully Integrated Process with Other IDP Elements

Overview: The interconnection process has traditionally been a part of grid operations (as opposed to planning). At Phase 4, the utility may further integrate planning and operation group activities. In this future state, interconnection may take a different form from streamlined studies, and may converge with other IDP elements as a highly-coordinated function within a fully streamlined IDP process. This integrated distribution planning process may bring about new ways for integrating DERs beyond reviewing and connecting DERs in an expedited fashion. There may be heightened requirements for visibility and potential control of DER output across the system to help coordinate and run the distribution grid. Locational benefit analysis may also actively direct locational and temporal specific deployment of DERs to maximize grid support and minimize the system impacts of DERs.

Key considerations and challenges: Reaching Phase 4 is dependent on the other elements of IDP, and how a utility looks to integrate and incorporate data from interconnection into the IDP process. Technology and interconnection tools will need expanded capabilities to better integrate with planning models between utility groups and help streamline communication and information sharing.

Phase 4 is a more aspirational future state, and the industry will face a number of challenges, both known (as listed in Phases 1-3) and unknown in the process to get there. The future state of interconnection is heavily dependent on the capabilities of the future grid modeling system, the utility and its stakeholders' vision and goals for the future distribution system, as well as the phase utilities reach in other IDP elements (e.g., load forecasting, hosting capacity). At this phase, utilities may need heightened capabilities to manage and operate the distribution system, while also providing customers and developers a certain level of autonomy over their choices.

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65 GridLab (2019), Integrated Distribution Planning A Path Forward, p. 11.

66 Ohio Public Utilities Commission (2020) (Facilitated by EnerNex), Distribution System Planning Working Group Final Report, p. 33.

Hosting Capacity Analysis

Hosting capacity is the amount of DER that the system can accommodate without negatively or adversely impacting critical factors (e.g., reliability, power quality, and voltage) under existing control and protection systems.[67] The role HCA plays in the IDP process is strongly dependent on the objectives and goals of the utility and its stakeholders. For example, utilities may strive for a comprehensive HCA approach to manage the interconnection process, or to leverage HCA as a planning tool to identify future constraints.[68] In these cases, HCA will serve an important role in IDP and may follow a phased approach to advance the sophistication of HCA. On the other hand, if hosting capacity analysis serves predominantly to help customers and third-parties identify areas with less system limitations (e.g., public HCA maps to inform stakeholders), HCA may play a more passive role in the IDP process.

Table 9 below presents a framework for the phased progression of hosting capacity analysis, which may advance along the phases differently based on the goals guiding the IDP process. These different approaches to enhance HCA may focus on one or a few of the following:

1. Level of automation
2. Depth of analysis
3. Frequency of analysis
4. Level of integration with other systems

Table 9: Progression of Hosting Capacity in IDP

<table>
<tr><th>Progression</th><th>Description</th><th>Paths for Phased Advancement</th></tr>
<tr><td>Phase 1</td><td>Limited, manual analysis: Hosting capacity analysis conducted reactively in response to customer interconnection requests.</td><td rowspan="4">May advance along phases focusing on one or a few of the following:
1. Level of automation
2. Depth of analysis
3. Frequency of analysis
4. Level of integration with other systems
Note: Dependent on goals and objectives of utility and stakeholder. Level of hosting capacity data shared and how data is shared outside of the utility is based on utility and stakeholder context.</td></tr>
<tr><td>Phase 2</td><td>Basic functionality with static analysis: Assessment and evaluation of a determined area, providing more general attributes (e.g., substation and feeder voltage, design limits, three-phase vs single phase).</td></tr>
<tr><td>Phase 3</td><td>Increasingly complex, iterative and/or coordinated analysis: Established process conducted on a more regular basis and could be coordinated with other systems or processes (e.g., interconnection process). Analysis in Phase 3 requires more sophisticated modeling capabilities, (e.g., feeder-level analysis with power flow modeling).</td></tr>
<tr><td>Phase 4</td><td>Fully integrated, continuous analysis with other IDP elements: Hosting capacity analysis may converge with other IDP elements (e.g., interconnection process and forecasting) in a streamlined and integrated manner. The future state of hosting capacity analysis may still be an unknown.</td></tr>
</table>

Source: Smart Electric Power Alliance, 2020.

67 U.S. DOE Office of Electricity Delivery & Energy Reliability (2017), Modern Distribution Grid, Volume I: Customer and State Policy Driven Functionality, p. 62.

68 U.S. Department of Energy (DOE) Office of Electricity (2020),DSPx Volume IV (Forthcoming report).

Phase 1: Limited, Manual Analysis

Overview: In Phase 1, a utility may conduct hosting capacity analysis on an ad hoc basis (e.g., to analyze single circuits in response to customer interconnection requests). At Phase 1, DER adoption is likely at low enough thresholds that analysis is limited to unique cases or more limited analysis (e.g., min/max loading).

Key considerations and challenges: The conditions at a utility (i.e., DER adoption, system conditions, stakeholder environment) will play the largest role in the challenges and considerations a utility may face. Some utilities at Phase 1 may begin to face pressure to advance to Phase 2 or 3 from municipality planners, DER developers, or their regulators. Other utilities may experience external pressures, but may look to advance internal analysis for distribution planning purposes. Utilities will need to determine whether to stay at Phase 1 and what future phase of hosting capacity analysis will be needed. Utilities and stakeholders will want to ensure a clear understanding of who needs hosting capacity information (internal versus external) and what is its purpose (i.e., inform planning, support municipality planning, support DER developers, support interconnection, etc.).

Phase 2: Basic Functionality with Static Analysis

Overview: Phase 2 expands HCA beyond one-off requests on specific circuits to an assessment of a determined area on a limited basis (e.g., annually). The area of the system under analysis is dependent on funding and needs for evaluation (e.g. system conditions, DER adoption levels). Frequency of analysis, specific use cases, and how hosting capacity data is incorporated into other utility systems (e.g., GIS) is contingent on each utility's unique circumstances. A handful of utilities interviewed for this paper sit within Phase 2 and have conducted or are developing methods for analysis on their system.

Key considerations and challenges: Utilities looking to transition from Phase 1 to more advanced phases of HCA tend to have higher system penetration of DERs (i.e., 2-15%).[69] However, DER adoption is only one potential indicator for potential needs for Phase 2 HCA. Other reasons may relate to existing system constraints, external pressures, or internal strategic planning. For a number of utilities participating in this study, Phase 2 HCA analysis required investment in new analytic tools. Other considerations at Phase 2 include:

- **Limitations of Phase 2 analysis:** HCA at this level can provide a ten-thousand foot view of the system to increase awareness of constraints along the system. Utilities stressed that at this phase, HCA should not determine whether to add DER resources along certain distribution feeders at this level, but rather indicate whether certain areas of the system may be closer to seeing violations. The robustness and accuracy of HCA will depend on the approach taken and depth of analysis, which as it becomes more sophisticated, shifts into Phase 3 analysis.
- **Different approaches and methodologies:** Currently, there lacks an industry standard or clear methodology for conducting HCA. Utilities use different methods, some of which are streamlined to simplify computational requirements, and others which require iterative detailed engineering analysis to increase complexity.[70] Due to different technical assumptions, methodologies can lead to different hosting capacity values, and also significantly impact the reliability and ability to inform grid planning and decision-making.[71] Clearly understanding the goals for HCA, and ensuring clear and aligned methodological choices and assumptions relate back to understanding the needs of the utility and its stakeholders.
- **Resource intensity considerations (e.g., approach, tools, and necessary computational complexity):** Some utilities have found conducting HCA today to be a largely manual process, thus requiring significant time and resources. This may factor into the depth of analysis, determined area, and frequency of analysis. Newer tools may help alleviate the manual burden of conducting this analysis.
- **Data quality and data management:** Utilities today are grappling with data quality and keeping data up-to-date to inform hosting capacity and other planning processes. The accuracy of analysis in these earlier stages of HCA is constrained by the data quality and inputs (e.g. limitations of interconnection records, circuit model parameters). Multiple utilities mentioned poor DER installation location records as a significant challenge.
- **Tools based on limited data and assumptions:** Some utilities felt that the tools assumed a certain level of visibility into customer assets (e.g., DER output, smart inverter settings) that for many utilities, is not easily obtained or available. Assumptions are therefore made

69 Ohio Public Utilities Commission (2020), Distribution System Planning Working Group Final Report, p. 35.

70 Paul De Martini, ICF International, Minnesota Public Utility Commission (2016), Integrated Distribution Planning, p. 8.

71 Interstate Renewable Energy Council (IREC) (2017), Optimizing the Grid: A Regulators Guide to Hosting Capacity Analysis for Distributed Energy Resources, p. 4.

as inputs into these tools and should be considered as possible limitations.

Phase 3: Increasingly Complex, Iterative and/or Coordinated Analysis

Overview: Each utility will drive the complexity and functionality of HCA at Phase 3. Some utilities envision Phase 3 will help move them closer to a state where they have closer visibility into the actual attributes of DERs on the grid, and eventually help evaluate resources based on the time of day. Others may see Phase 3 as an opportunity to ramp up the frequency of HCA or the development of an HCA process that is closely coordinated with interconnection queues.

As noted in Table 9, automation, depth of analysis, frequency of analysis, and level of integration are different factors that can influence the scope of Phase 3. Regardless of which factors are at play, this phase will require more sophisticated modeling tools and technology for data accuracy and management. Depending on the objectives and needs at a utility and by stakeholders, data may be shared publicly.

Key considerations and challenges: Reaching Phase 3 will require greater maturity and commercial availability of HCA tools to enable more sophisticated analysis, as well as potential integration with other systems. As mentioned above, the need for shifting to Phase 3 and the form HCA may take at this stage is contingent on the needs, purpose, and goals utilities and their stakeholders are trying to achieve.

Challenges at Phase 3 will be highly dependent on the unique path each utility takes and the needs they are looking to meet, but broad considerations include:

- **Clear uses and goals defined at the outset:** Utilities need to have clearly defined uses and goals for HCA before commencement of a hosting capacity process. Not doing so runs the risk of duplicative expenditures if a state or utility selects a HCA methodology that may not serve the goal(s) or use cases.[72]

  For example, in California, the CPUC specified a goal for HCA to improve the efficiency of interconnection processes. After utilities completed initial deployments and reviewed different methodologies and stakeholder input, the originally selected streamlined methodology was found to be inadequate in meeting interconnection goals, and an iterative methodology was a better fit to produce the accuracy and precision needed for their interconnection use case.[73]

- **Significant time and investment needed to reach Phase 3 levels:** Whether utilities are looking to increase the depth of analysis or are planning to automate, integrate, or increase frequency of analysis, they will need to invest a significant amount of time and resources to reach Phase 3 levels. As utilities look to run HCA at the feeder or more granular levels, increased integrations and investments will be necessary.
- **Maturity and commercial availability of hosting capacity tools:** Utilities will need to acquire new tools with advanced methodologies, approaches, and capabilities to automate or coordinate with other IDP processes. Utilities noted that tools to help with time series analysis are just getting to Phase 3 capabilities as of the date of this report.
- **Computational complexity and data requirements:** As utilities move closer towards time series analysis or load curve analysis, they need to collect and incorporate the timing of when DER systems come online. Utilities may or may not have this information easily available today. Planners will also need to consider what data is required when transitioning from static to time series analysis.
- **Data quality as a foundation for accurate results:** Data quality is the foundation for obtaining accurate results, and Phase 3 analysis assumes more granular, high quality data is available to input into HCA. Challenges in data quality exist today (see Forecasting), which utilities will need to consider as they approach Phase 3.
- **Data security:** Data security is a key consideration, especially when a utility is seeking to make information public to meet needs from stakeholders (e.g., municipalities, DER developers, customers). Establishing a secure method of sharing appropriate information with customers and developers will be necessary, while securing personally identifiable and competitive customer information. There may be significant security implications if sensitive system data (e.g., location of sensitive loads and system assets) got into the hands of malicious actors.

Phase 4: Fully Integrated, Continuous Analysis with Other IDP Elements

Overview: Phase 4 represents a future state in which hosting capacity analysis may be fully integrated, automated, and continuous. HCA may at this stage converge with other IDP elements (e.g., interconnection

72 IREC (2017), p. 9-11.

73 IREC (2017), p. 9-11.

information application, forecasting based on granular data) and no longer exist as a discrete element or separate process to coordinate with. Analysis at this stage would look at annual 8760-hour load profiles (or even 15 minute or smaller intervals), and could run continuously for near real-time updates. Phase 4 may expand capabilities to more real-time dynamic hosting capacity analysis, in which utilities may monitor and control DERs in relation to hosting capacity at various locations, and at times help maximize value from interconnected DERs. Evaluation may also more comprehensively consider aspects such as protection, reliability and safety.

HCA is still in a more nascent stage, and its future state is still largely unknown and dependent on the unique needs of each utility.

Key considerations and challenges: Reaching Phase 4 exists as a more aspirational phase that may be more achievable in the coming decade(s) as data availability, commercial tools and capabilities improve, and as utilities invest in advanced technologies, system integrations and expanded staff skill sets. Key considerations in reaching this advanced phase include:

- **Data requirements and expanded analytic capabilities:** As HCA and other IDP elements converge at later phases, utilities will need granular data at the hourly or sub-hourly level. Utilities will need to overcome challenges of masked load as they deploy technology to collect more granular customer data (e.g., native load, net load, generation output of DERs, other forms of measurement of DER performance). Handling this data at the hourly level for customers will require new analytic techniques (e.g. data compression) to manage and incorporate an exponentially greater amount of data into powerflow analysis.
- **System requirements:** While technology recommendations are beyond the scope of this paper, the ability to integrate, automate, and monitor and control DERs at Phase 4 likely necessitate ADMS, DERMS, analytics platforms and other investments to enable coordination, control and forecasting of DERs.
- **Interdependencies between IDP elements:** As utilities look to approach Phase 4, a strong linkage exists with other areas of the IDP process (e.g., forecasting, interconnection information integration). Continuous analysis at Phase 4 would require all other systems feeding data into HCA to be continuous, including information from customer DER interconnections, voltage and contingency operations, and real-time output and forecasts of customers load and their DERs.
- **Complexity of data:** The complexity of analysis at Phase 4 may require machine learning in the future to look at 8760 profiles to see how DERs interact with other equipment along the system and identify the most critical times of day, allowing utilities to focus their time and resources.

Stakeholder Engagement

Stakeholder engagement is a key differentiator when transitioning from traditional distribution planning to IDP. However, the approach to stakeholder engagement will be unique to each jurisdiction and the needs of the utility and its stakeholders. Stakeholder engagement can be incorporated in various stages of the IDP process (e.g., forecasting, sourcing solutions for grid needs, and HCA). The following section identifies potential stakeholder groups and benefits of engagement, highlights challenges and considerations when establishing an engagement process, and outlines different approaches (see Figure 6).

Defining stakeholders: Multiple groups fall under the category of "stakeholder" including customers, developers, advocacy groups (e.g. consumer and environmental), state government entities, regulatory bodies and community organizations, among others. While these stakeholder groups have unique perspectives and interest in distribution planning, they can generally be placed into three different classifications: 1) industry stakeholders, 2) community and customer stakeholders, and 3) public stakeholders.

Industry stakeholders generally include groups such as developers, third party aggregators, industry non-profits, research organizations, and other groups that work within the electric power industry. Engagement with these groups can provide utilities with visibility into upcoming projects and sourcing solutions for NWAs. Industry stakeholders, such as developers and third party aggregators, have a unique perspective into where projects are being sited and coming online, which can be valuable inputs to the planning process. Additionally, when engaging this group of stakeholders, the utility is really engaging the marketplace which can lead to innovative solutions and partnerships to solve grid constraints.

Community and customer stakeholders often include utility customers or groups that own facilities inside the utility service territory, including key accounts, residential customers, government agencies, cities, and counties, in addition to other members of the community. Engagement with these groups is valuable to better understand customer and community needs when conducting planning, as well as foster community buy-in for system upgrades and other investments. Effective communication with the community can also lead to joint investment opportunities in projects that solve both community and grid needs. For example, a microgrid can function both as a distribution deferral asset and a source of back-up power to a designated emergency shelter or community center for added community resilience during a prolonged outage. It is important to educate community and customer stakeholders upfront on the planning process to identify mutual benefits and goals to yield better investments for the community and utility customers.

Public stakeholders typically include community or advocacy groups such as consumer and environmental advocates, community organizers, and other special interest groups. These groups value transparency and visibility into the inputs and decisions made during the planning process. Distribution planning is complex and it is important to educate the public stakeholders on the planning process to effectively solicit input and communicate decision making throughout. Doing so can help avoid contention through formal intervention in regulatory or permitting proceedings later in the process.

Key Challenges: Stakeholder processes have also run up against a handful of key challenges, some of which are detailed below.

- **Resource intensive process:** Stakeholder engagement processes can be time and resource intensive, with a need for dedicated time commitments from utility resources and changes to internal processes. These efforts should be taken into consideration in relation to the timing and expectations for IDP development. Distribution planning often seeks to solve specific problems that are expected to appear at a distinct point in the future. Planned solutions must have time for execution before the problem or constraint materializes. Thus, the process must define time limits on stakeholder participation to ensure solutions are crafted in a timely manner to address challenges that could impact system reliability. Additionally, the utility may need to lengthen lead times for IDP processes depending on the area where stakeholder engagement is incorporated and the engagement approach.
- **Bringing the right people to the table:** Attracting key stakeholders to participate helps to ensure a balanced and productive process. Beyond the usual stakeholders involved with utilities, lessons from California note the need to bring local government planning into the effort. With clean energy targets and policies driving IDP processes, it is important to note the strong link between greenhouse gas emissions and urban planning (housing density, land use, building codes, mobility services).[74] Taking into account this connection and ensuring collaboration between the distribution utility, local government, and other key stakeholders will help with effective planning.
- **Ensuring balanced perspectives and productive input:** An additional challenge is the need for checks and balances between managerial discretion and stakeholder inputs during the process. Having a clear set of goals and objectives across stakeholders will help ensure productive discussion and obtain effective and balanced input. A clear structure and approach will also help facilitate productive input. For sensitive and contentious topics (e.g., data sharing), the process may occur within legal boundaries, or require regulatory/board approval or clarity from the decision-making authority.
- **Data security:** Data sharing and privacy of customer information is a key concern for utilities when it comes to stakeholder engagement and sharing information with third parties. Most, if not all utilities are reluctant to share data due to a lack of internal and external protocols for data sharing, as well as the absence of secure tools and capabilities. The industry will need to overcome challenges, including liability for compromised and sensitive data falling into malicious actors' hands, and secure protocols for sharing information.

Guiding Principles/Key Considerations: Below are recommendations and guidance to effectively engage stakeholders in IDP.

- **Clearly defined stakeholder process:** It is essential to clearly define the process and establish parameters to address the following key considerations: 1) Who is a stakeholder; 2) What is the level of engagement; 3) Where in the process is input captured; and 4) How is the input incorporated?
- **Defining who is involved in the process:** The term "stakeholder" oftentimes is used as a blanket term and

74 GridWorks (2019), DRP Retrospective Chapter Seven: Next Steps and Future Challenges.

goes undefined in the planning process. Identifying the appropriate stakeholder groups is critical to effective engagement in the planning process. These groups will differ depending on the desired outcome and type of engagement. Identification of stakeholder groups is not meant to be exclusionary, but rather to ensure efficient and effective engagement.

- **Identifying the types of engagement:** As noted in Figure 6 below, different approaches to stakeholder engagement vary in terms of structure, resource intensity, and cost. The type of engagement can have a big impact on the result of the engagement. For instance, if the goal of engagement is to create dialog between stakeholder groups to better understand their perspectives and work together to solve a problem, a less formal and more conversational setting is beneficial. This will be less confrontational than a litigated step in a docket, and stakeholders will be more apt to work with one another when they do not feel they have to argue their points for the record. Ultimately, the goals and desired outcomes of the process should dictate the type of engagement.
- **Ensuring a timely process:** When and where the engagement occurs within the planning process is also crucial. Utilities are responsible for maintaining the safety and reliability of the grid, and the planning process plays a large role in enabling them to do so. Stakeholder engagement can be a tool to inform and enhance the process. However, a clear structure and timeframe for engagement must be in place to ensure distribution planning is not delayed or impeded.
- **Establishing clear expectations:** Before conducting stakeholder engagement, a clear process should be established that outlines how the utility is expected to incorporate input from stakeholders into planning considerations. This includes whether or not it is left up to the utility's discretion if stakeholder input is incorporated into planning considerations or if there is required justification.

Figure 6: Approaches to Stakeholder Engagement in IDP

Limited and Internally Driven	Informative Outreach
Little to no engagement in the planning process. Interactions only occur after a capital budget plan is filed.	Engagement is educational and meant to inform stakeholders of the utility's planning process. Communication happens prior to the start of the planning process. Types of engagement may include: ▪ In-person workshops and open houses ▪ "Town Hall" meetings ▪ Webinars
Proactive Engagement	**Incorporated**
Two-way information flow between the utility and stakeholders. Engagement is proactive and informs portions of the planning process such as forecasting and identifying potential NWAs. Types of engagement may include: ▪ Dedicated working groups ▪ Data sharing (e.g. DER developers) ▪ RFI solicitation for potential NWAs	Formalized engagements included throughout the planning process. Characteristics may include: ▪ Stakeholder collaborative groups ▪ Established external touchpoints ▪ Data sharing portals

Source: Smart Electric Power Alliance, 2020.

Conclusion

While traditional distribution planning has met, and for many utilities continues to meet, core needs for providing safe, reliable, and affordable delivery of electricity, growing DER adoption, changing customer behaviors, and significant technological advances are bringing increased complexity to the distribution grid. For a number of utilities, these changing conditions signal the need to evaluate IDP.

The journey towards IDP will be unique for each utility and state, with utilities beginning from different starting points and guided by varying goals, objectives, and visions for the future grid. Acknowledging no one-size-fits-all solution to IDP, and that many operational, technical, regulatory and even legal challenges lie ahead, this paper proposes an incremental, phased approach. The IDP phased progression framework (Figure 4) lays out this progression starting at traditional planning processes and transitioning to a more aspirational future state for IDP (Phase 4). The paper breaks down the IDP process into the most common elements, and discusses key considerations and challenges at each phased advancement.

Across the many considerations discussed throughout this paper, a few key challenges will be crucial to overcome in the coming years to help advance IDP, including:

- **Bridging existing technology gaps and investing in foundational grid investments for future planning:** Utilities need to continue developing advanced planning and operational tools (e.g., TDG integration tools, DER forecasting, DERMS) to provide grid visibility and control, and to better integrate DERs into grid planning and grid operations. Other required investments along the distribution grid, include adding additional meters, measurement points, communication nodes, control points and other capabilities. These investments should take place within a more holistic investment approach, viewing distribution investments alongside asset management, grid modernization, and resilience efforts.
- **Investing and building competencies in big data at utilities:** As utilities advance to later phases of IDP, the complexity of collecting, managing, and analyzing increasingly granular data will grow. Information technology and operational technology (IT/OT) integration will face growing pains in integrating different structures and working with new and larger sets of data. Significant amounts of time and investment in resources are required to help prepare for this future, which includes investment in people (e.g., staff training, talent acquisition), tools (e.g., cloud operations for data storage), and standardized analytics to ensure data quality, security, and accuracy in the future.
- **Change management and integration of systems, groups, processes:** As utilities transition from traditional distribution planning to IDP, a considerable amount of time and effort will be required to integrate disparate systems, tools, and groups within a utility. In some cases, the systems and tools needed to enable integration may yet to be developed. This will only compound when coordinating across transmission, distribution, and generation planning.
- **Increased training and investment in staff:** Within the context of big data management, utility staff will need increased training and talent acquisition to navigate an increasingly technically complex distribution grid, including progressively more complicated interconnection processes, and new tools and software.
- **Determining value of DERs for grid services:** Determining locational and temporal value, and evaluating the benefits and costs of DERs on the grid at any given time will play a key role in integrating and planning for DERs in the future. Methodologies for evaluating DERs and determining locational and temporal value vary by utility, jurisdiction, regulatory compliance mandates, and market. Challenges exist in assessing and assigning numerical locational and temporal values today, and further research and investment to streamline locational and temporal analysis will be required to enable more advanced integrated planning in the future.
- **New Regulatory Constructs:** The ability for utilities to advance to more mature phases of IDP may be limited by existing regulatory constructs. These regulatory constructs likely need to evolve to lay the groundwork needed for IDP, as well as to open up opportunities for new business models for grid solutions.

Recommendations

Based on the findings in this report, SEPA recommends utilities, regulators, and stakeholders consider the following as they look to advance IDP efforts.

- **Have clear vision, goals, and objectives to guide IDP:** Utilities and regulators need a clear vision and guiding goals and objectives to help determine steps in the IDP process. As noted throughout the report, there is no one-size-fits-all approach to IDP.

- **Consider key inputs and existing capabilities to determine starting and future points for IDP:** Utilities will need to assess where they are today and their desired future IDP state based on their goals and objectives, as well as the existing technical capabilities, investments, and processes. Understanding their current and desired future state will help lay out the incremental considerations to account for along the way.
- **Allow lead time and investment in capability building:** The implementation of new tools, systems, and processes will not take place overnight. Utilities, regulators, and stakeholders should allow appropriate lead time to invest in, and implement necessary tools, staff training and grid capabilities to enable advanced planning.
- **Continued education from utilities to non-utility stakeholders and regulators:** Traditional planning processes have predominantly existed internally at the utility. As these processes evolve to increase transparency and include stakeholder engagement, utilities will need to further share with and educate the broader industry on their planning processes and technical capabilities, as well as limitations.
- **Further investment and research into planning and operational tools and technologies:** The industry will benefit from a more detailed evaluation of the grid tools and investments necessary to enable advanced planning capabilities. Furthermore, the explicit identification of technology and capability gaps in planning and operational software will be necessary to help industry stakeholders meet the planning needs of the future.

With these considerations and recommendations in mind, utilities should develop utility- and jurisdiction-specific roadmaps. The framework provided in this paper is intended to help utilities and regulators evaluate their starting point, and the steps to take in the near- to long-term to establish capabilities for integrated distribution planning.

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