2025 White Paper

Enabling Distributed Energy Resource Services in Distribution Operations

TABLE OF CONTENTS

INTRODUCTION

The electric power distribution system is in a state of transformation. Where once the distribution system was a delivery mechanism, carrying energy from the bulk power system to end use customers, its purpose is expanding to both deliver energy to customers and also serve as a platform to host distributed energy resources (DER). In this paper DER includes a broad set resources including distributed generation, storage, demand response, as well as managed electric vehicle (EV) charging. The evolution of distribution system operations to best leverage and utilize DER will progress through many projects and initiatives that create new capabilities or enhance the maturity of an existing capability for a utility.

A capability is a description of what a utility is able to do in terms of the collective expertise, processes, and technologies that are leveraged to complete a specific task or function.[1] Utilities have a spectrum of existing capabilities that allow them to conduct business today. The evolution of distribution system operations will require new or more mature capabilities to achieve the objectives of increased DER integration and utilization.

Careful forethought in the design of DER initiatives can ensure that the operational capabilities are able to accommodate, manage, and optimize DER in accordance with DER program structures as they are deployed. Examples of DER programs and associated capabilities include:

- Energy Production (DER interconnection, smart inverter settings management, flexible interconnections)
- Load Modification (demand response, TOU rates, managed EV charging)
- Reliability (microgrids, non-wires solutions, DER integrated FLISR)
- Market Based Services (FERC Order 2222, integrated transmission and distribution (T&D) services)

The enablement of DER services will require capability enhancement across almost every function within the electric utility. While recognizing the need for significant cross-functional coordination, this paper focuses on those issues and opportunities specific to distribution operations, and primarily control center functions.

1 *Grid Modernization Playbook: A Framework for Developing Your Plan.* EPRI, Palo Alto, CA: 2023. 3002026985.

The mix of program offerings, and the structure of those programs, will define the scope and scale of operational capabilities needed. As there could be a wide range of possible implementation plans, this paper discusses capabilities in relatively broad terms aligned with the anticipated evolution of the distribution system as developed by the U.S. Department of Energy (DOE).

DOE developed a framework to describe an envisioned evolution of distribution systems with respect to enabling DERs. At its core, the framework posits that the evolution of the distribution system will be driven both by bottom-up and top-down drivers. Bottom-up drivers include customer adoption of new technologies and participation in DER service offerings, and overarching top-down drivers include policy and regulatory direction such as FERC Order 2222.[2] This framework, graphically represented in Figure 1, identifies three primary stages of the evolution based on the scope and scale of DER integration and utilization. While the evolution of distribution systems will vary from location to location, the three stages presented in the framework can help guide the development of capabilities (people, processes and technology) that would enable different levels of DER integration in grid operations.

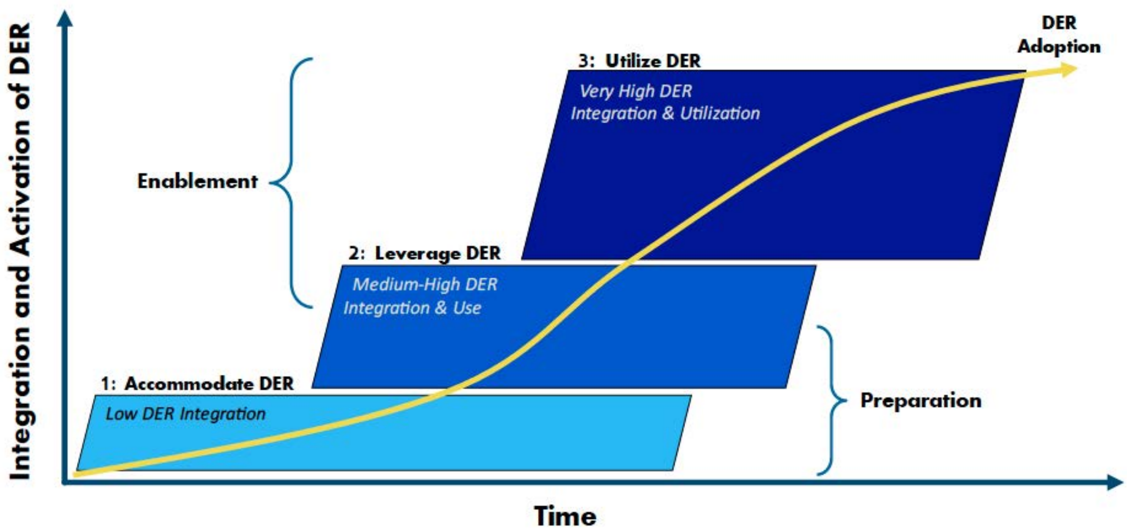


Figure 1. *Distribution System Evolution – Source: DOE*

The yellow arrow in Figure 1indicates a general trend for DER adoption as it relates to the evolutionary stages. Assigning specific penetration or interconnection volumes is not practical for this graphic as the transition between stages is not dependent on those values. In some cases, local, state, or federal policy may require a utility to advance from stage 1 to stage 2 and so on, even if the aggregate penetration is low enough to not require DER management to maintain system reliability. Conversely, some utilities with rapid DER growth may need to adopt DER technologies to maintain reliability in the absence of policies requiring the development of service programs or opportunities for DER. Therefore, a specific DER adoption threshold cannot be established to dictate when a transition between stages is required for all utilities.

2 Federal Energy Regulatory Commission, "Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators," Order No. 2222, issued September 17, 2020. https://www.ferc.gov/sites/default/files/2020-09/E-1_0.pdf.

Stage 1 – Accommodate DER

DER penetrations are low as a percentage of system peak but there may be localized pockets of higher penetrations. DER typically are compensated based on systemwide tariffs such as net metering and simple incentives (e.g., for smart thermostats). However, there are cases where utilities have implemented incentive programs to reduce peak load on a circuit or substation even though overall DER penetration does not justify such programs system wide. Distribution systems are planned for worst case conditions that may occur infrequently during the year. The grid operator's[3] focus is on safety, capacity, and reliability. With capacity reserves driven by worst case planning and autonomous equipment settings, operator actions are generally reactive, intervening only in abnormal conditions. Early in this stage, DER may be considered more of an operational liability than a grid supporting resource. As DER penetrations increase and operational capabilities are enhanced, smart inverter technologies may be utilized to mitigate local capacity constraints as permitted or required by the tariff. Many new or expanded capabilities needed to enable DER to access additional value streams in Stage 2 hinge upon the availability and successful development of foundational capabilities during Stage 1.

Stage 2 – Leverage DER

Stage 2 is marked by a shift from accommodating DER to enabling DER, impacting both planning and operations. In this transitional stage, DER penetrations have increased in some locations to the point where they can be an actively managed resource to address specific local grid needs. These needs will have unique DER performance requirements and may be limited to targeted locations where conditions warrant the use of DER and where there is sufficient DER to address the underlying issue. Crafting a DER solution to the grid need is commonly referred to as a Non-Wires Solution (NWS).[4] The DER that comprise NWS are typically compensated via individual contracts with terms and conditions specific to each use case. NWS may be dispatched on an as-needed basis. Distribution system operations must become more proactive and granular, with a broadened focus on DER availability, variable capacity, and marginal costs to leverage these resources for grid services.

As adoption continues to expand, financial incentive structures for DERs are reexamined. Public policy initiatives at the local, state, and federal level (e.g., FERC Order 2222) create opportunities for DER owners and developers to access new value streams such as revenues from wholesale electricity markets and NWS contracts with utilities. New actors such a DER Aggregators emerge to help orchestrate the management of DER and assist DER owners and utilities realize the benefit of DER services. Utilities focus on technologies and systems to support these public policy goals while maintaining a firm grasp on minimizing costs and maintaining safety and reliability.

Stage 3 – Utilize DER

Building off the experience and capability maturity gained in Stages 1 and 2, Stage 3 posits DER as an integral component of the distribution and bulk power systems. DER penetration and load management capabilities are sufficient to enable the aggregation of resources into virtual power plants (VPP) that compete for market-based services in both distribution and wholesale markets. DER Aggregators, which could be third parties or utilities, actively recruit resources both large and small to participate in the programs and opportunities available. Grid and market operators become reliant on these resources to not only supply a growing portion of electricity demand but also to provide functionality in terms of resilience, voltage reactive power support, and frequency regulation through distribution and transmission grid services. The scope and scale of DER services may vary daily based on market prices and other revenue opportunities DER providers may have. Therefore, managed DER is fully integrated into daily operations, and distribution operators must know what resources are available at any given time and the technical and economic impacts of various dispatch schedules. Similarly, system planning rigorously considers DER, whether customer or utility owned, as a grid asset necessitating closely coordinated integrated transmission, distribution, and generation planning. In Stage 3, advanced grid and DER management

3 Today the operation of the distribution system is solely the domain of utilities. In the future a non-utility management entity may be responsible for DER operation to facilitate the provision of DER grid services.

4 Also called Non-Wires Alternatives.

capabilities are ubiquitous, and planning standards have evolved to leverage the full benefit of DER.

Need for Roadmap and Cost Recovery Plan for Foundational Investments

As the distribution system evolution unfolds – creating a more dynamic, automated, and resilient future state – new roles and responsibilities, capabilities, and analytics will be needed in the distribution control center. Roles and responsibilities within distribution operations will expand to include coordination and control of DER in concert with traditional assets (poles, wires, transformers) to meet reliability and energy goals. Similar to balancing authorities for the bulk power system, a future vision of distribution operations is modulating DER and load in a way that meets local energy and distribution needs. A system of one-way streets is evolving into a transportation network that accommodates multidirectional travel all while minimizing traffic jams along the way and into the future.

Recognizing that the transition underway is a multi-step process, and that the pace of change within the industry continues to accelerate, a well-developed strategy is key to achieving utility objectives, meeting state and local goals, and minimizing risk. Utilities need to understand where they currently stand and where they envision going in order to develop their strategy. Depending on where a utility lies in the broad spectrum of technology adoption, process standardization, and overall grid modernization efforts, the pathway to achieving the stated vision of the distribution operations organization will differ, but all utilities will likely need to undertake many initiatives and investments.

Key questions for the industry include what capabilities are needed, where to start, and how quickly to progress? Initiatives need to be thoughtfully sequenced over time to support the needs of today while laying a foundation for the technologies required over the horizon to cost-effectively enable the envisioned future of distribution operations.

To help utilities meet evolving grid needs, the Electric Power Research Institute (EPRI) developed a framework leveraging concepts described in DOE's Distribution System Platform of the Future (DSPx) project (see *Framework for Strategic Roadmap Development*).[5] This grid modernization framework[6] is an optic through which to examine distribution system evolution and develop a staged investment strategy that enables utilities to achieve their vision of the evolutionary pathway.

The objective of this paper is to establish an industry roadmap for future distribution operations requirements. In this roadmap, capabilities are represented as a spectrum across which a utility can progress. Some capabilities can be utilized in all three stages of grid evolution, and expenditures to achieve these capabilities are often considered "no-regrets" solutions. These investments and expenses can immediately enhance existing operational practices, improving safety and reliability, reducing costs, or facilitating customer enablement. At the same time, they provide the supporting foundation upon which other capabilities may be added in the future. Other capabilities may be necessary only when specific opportunities for harnessing DER are planned. Finally, some capabilities are related and interdependent, meaning that a broader set of investments and well-coordinated implementation plans are needed. All of these factors influence the logical sequence of investments needed to achieve the desired operational capabilities.

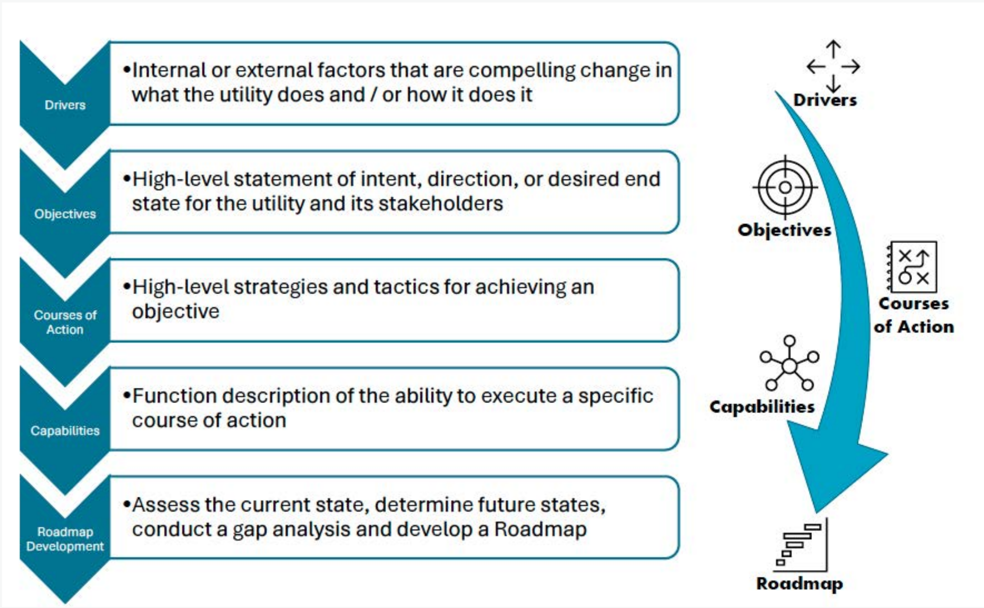
The resulting roadmap provides a common understanding of the necessary capabilities while enabling utilities to chart a staged approach that is pragmatic for their unique positions and with built-in flexibility to identify decision points and pivot as conditions dictate.

5 Modern Distribution Grid, Volumes I-IV, U.S. Department of Energy, Office of Electricity Delivery & Energy Reliability. https://gridarchitecture.pnnl.gov/modern-grid-distribution-project.aspx.

6 *Grid Modernization Playbook: A Framework for Developing Your Plan*. EPRI, Palo Alto, CA: 2023. 3002026985.

Framework for Strategic Roadmap Development

EPRI developed a framework to help utilities develop strategic plans to meet the evolving requirements of a modern grid, leveraging concepts described in DOE's DSPx project. This framework includes core building blocks for foundational or enabling capabilities and advanced functions for nascent or emerging capabilities that may be needed in the future. The framework includes five steps to determine which capabilities are needed for a given future state and provides guidance for developing a pragmatic approach to acquiring those capabilities over time.



This high-level process provides guiderails for distribution grid modernization planning. Having clear objectives that convey scope and expectations helps ensure that the plan is focused and achievable. Considering the broader implications through an integrated planning lens identifies foundational investments that may benefit multiple disciplines within the utility. Applying a system engineering approach aligns technology choices with stated objectives. Finally, a staged deployment strategy can satisfy near-term requirements with cost-effective solutions, followed by more sophisticated approaches, as needed. The framework is intended to help utilities navigate their unique drivers and objectives, identify pragmatic courses of actions, and develop a roadmap for the capabilities that are required.

INDUSTRY ROADMAP: ENABLING DER SERVICES THROUGH DISTRIBUTION OPERATIONS

The enablement of DER to provide services to the grid touches all facets of a utility's organization. From planning to operation to cyber security to customer accounts, utilities require a range of activities to prepare for the future. While much thought has been given to DER technology, interconnection practices, planning paradigms, and rate structures, less attention has been paid to the operational capabilities required to enable the future vision.

Distribution operations groups are at the front lines of grid management, a fact which will not change in the future. The control center will ultimately be responsible for managing a much more dynamic distribution system, orchestrating the management of traditional grid assets in concert with a manifold of customer and utility owned DER. However, operations groups are typically only tangentially involved in discussions surrounding DER strategy, resulting in reactionary initiatives to meet the needs of the latest corporate, regulatory, or board directive. To address this gap, this roadmap focuses on enhancing capabilities within the distribution operations organization.

While the people, processes, and tools presented in the roadmap are focused on the control center, close coordination with planning, telecommunications, customer accounts, and other functions will be critical to enable the desired DER integration and utilization. Where applicable, dependencies and impacts across supporting groups will be noted.

Drivers

Utilities throughout the United States and across the globe are being pushed – both internally and externally – to increasingly integrate and utilize DER. This is being driven by DER adoption as well as public policy initiatives. DER adoption may follow a technology 'S Curve' that accelerates as technology matures and becomes more affordable before ultimately reaching saturation, as shown in Figure 2. However, DER adoption and utilization also are influenced by specific public policy initiatives, including financial incentives. Meanwhile, broader state policy initiatives are steering utilities and society in a direction that benefits goals such as decarbonization, equity, and climate resilience.

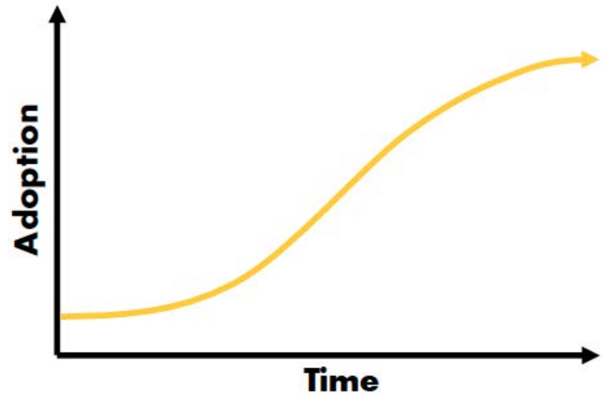


Figure 2. *Example technology adoption 'S Curve'*

Neither bottom-up technology adoption or top-down policy alone dictates a utility's urgency and direction for DER enablement. Rather, the combination of these two drivers influences when and where a utility will make investments needed to integrate DERs. This roadmap discusses capabilities and investments related to both customer adoption and public policy goals, allowing each utility to chart its own path.

Objectives and Courses of Action

Operational objectives will expand as a utility progresses through the stages represented in DOE's evolutionary framework presented earlier in Figure 1. The three evolutionary stages envisioned by DOE do not have clear boundaries. Instead, they are a continuum of grid transformation. Each stage represents a state of evolution, characterized by varying degrees of DER integration, grid management capabilities, and market interactions. Activities undertaken to meet objectives for stage 1 are foundational to stage 2 and so on. Regarding DER, the primary objective across these stages is to increase DER integration and utilization. Nevertheless, within each stage there are more granular objectives to increasingly leverage DER to support grid operations in a cost-effective and reliable manner.

To realize each objective, utilities will need to progress through multiple well-coordinated initiatives, referred to as courses of action within EPRI's road-mapping framework. This industry roadmap describes capability milestones needed to reach the broader objective of enabling DER services, from which a utility can define its own near-term objectives to meet specific milestones. The utility can then craft one or more courses of action that it will take to realize its desired state. If, for example, a utility's objective is to increase DER integration through a flexible interconnection[7] program, it may develop courses of action such as:

- increasing visibility and situational awareness of DER capacity restrictions in operational time frames[8]
- creating a communication strategy for interfacing utility systems with third party devices[9]
- formulating a method for allocating the grid constraint among the impacted DER in the form of a curtailment plan[10]

While DOE's evolutionary framework is broadly applicable to the electricity industry, the courses of action that are applicable to a given utility must be developed and aligned with its present state and the nuances of its local drivers and objectives. The capability roadmaps presented in the next section allow utilities to identify gaps within their current processes and practices, in turn enabling them to identify near term objectives and related courses of action.

Operational Capabilities Needed to Enable DER Services

Safe and reliable operations will always be paramount for distribution operators. The timeframes for operators to identify and react to emerging situations can be week-ahead, day-ahead, near real-time, and in real-time. Enhancing capabilities such as situational awareness, monitoring and control, outage management, and automation to improve grid performance are foundational at all levels of DER penetration. To operationalize DER services, operational planning, DER management, and system optimization capabilities will be needed. Developing these capabilities will require the integration of new capabilities with enhanced versions of many foundational capabilities. Therefore, when developing the system requirements of foundational capabilities today, care should be taken to consider envisioned future DER service opportunities.

Figure 2 presents operational functionality as six core capabilities. To realize these functional capabilities will require well-coordinated initiatives that appropriately staff and train the workforce, develop efficient processes, and integrate advanced technologies.

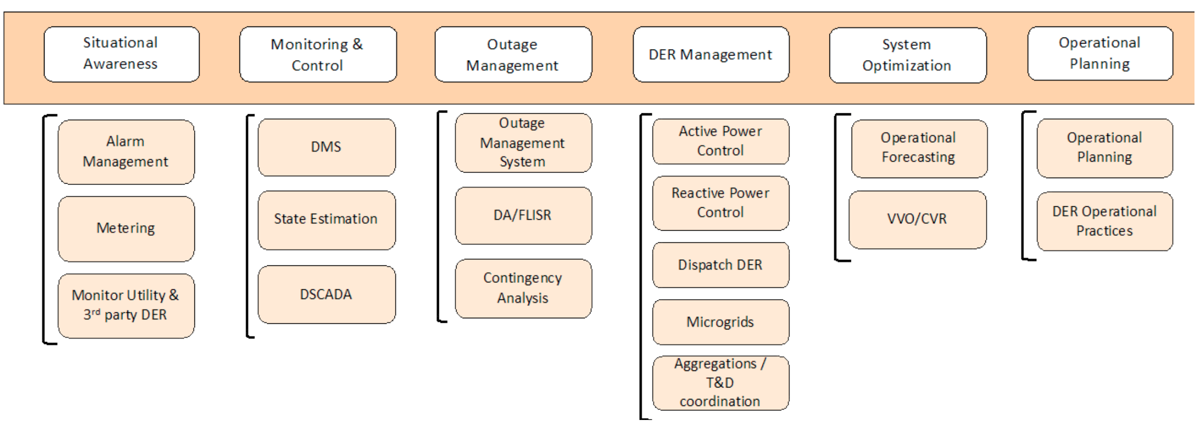


Figure 3. *Future operational capabilities needed to enable DER services*

7 Flexible interconnection is a term that describes dynamically adjusting injection or demand limits for DER to ensure the grid remains within physical and operational bounds. *Understanding Flexible Interconnection*. EPRI, Palo Alto, CA: 2018. 3002014475.

8 *Making the Connection: The Importance of DER Visibility to Grid Support and Modernization*. EPRI, Palo Alto, CA: 2018. 3002013388.

9 *Communication Requirements for DER: Update on Testbed Requirements and Configuration*. EPRI, Palo Alto, CA: 2023. 3002028191.

10 *Managing Flexibility on the Distribution System with Dynamic Operating Envelopes*. EPRI, Palo Alto, CA: 2022. 3002025065.

The following sections describe each high-level operations capability in Figure 3 and a vision of how the capabilities across the stages of DER enablement will need to evolve with respect to people, process and technology. Also discussed is roadmap for each operations capability.

Situational Awareness

This group of capabilities focuses on increasing the distribution operator's understanding of current and imminent local grid conditions to support effective operational decision-making and response. Distribution operators are tasked with a wide array of responsibilities, but the overarching goal is to maintain service delivery to all customers while keeping grid assets within physical and operational limits. Therefore, operators need to have visibility to or awareness of device statuses, line voltages and currents, as well as outages on the system. Enabling DER services will require more granular situational awareness and tools that increase visibility and provide additional information. This capability group includes customer metering, real-time monitoring of grid and DER assets, alarm management, and analytical tools that extract informative value from disparate data sources.

The existence of data alone does not equate to increased situational awareness, however. Rather, situational awareness manifests when this data is cleaned, analyzed and appropriately presented in a form that is digestible by system operators and engineering support staff. To accomplish these goals, the operations organization will need to rely on information technology (IT) and operational technology (OT) staff to integrate the data and cyber security staff to secure the data.

Beyond the deployment of data collection and communication technologies, leveraging this data in operational tools will require technical staff to build and maintain grid models and properly integrate the array of data into those models. Management and governance of grid data (models, measurements, and telemetry) are foundational capabilities, as is a mature understanding of how both model and measurement data errors can propagate to a lack of visibility to — or misrepresentation of — the state of the distribution system.

Table 1 describes how the people, processes, and technology that comprise situational awareness will need to evolve through the three stages of DER enablement.

Table 1. *Evolving people, process, and technology for situational awareness*

	People	Process	Technology
Stage 1	IT/OT Support Staff	DER Visible on SCADA Displays	DSCADA & Displays
Stage 2	Upskilled Operators	Operating Practices Leverage Meas. Data	DMS Load-Flow
Stage 3	DER Data Manager	Day-Ahead Dispatch Security Evaluation	State Estimation with Scenario Functionality

The control center is already becoming increasingly dependent on IT/OT staff to support data integration and upkeep. As additional streams of data from Distribution Supervisory Control and Data Acquisition (DSCADA), advanced metering infrastructure (AMI), and a growing fleet of connected grid devices are brought into the control room to support DER enablement, the role of IT/OT staff will need to expand, as depicted in Table 1.

People

In stage 1, additional resources for current staff may be warranted for widespread deployment of DSCADA and AMI. This role includes data management for new streams of data that are available. In stage 2, when accurate real-time load flow solutions and appropriate alarming of DER are needed, system operators will need to be trained in the use of this data to identify imminent threats to safety and reliability, as well as appropriate response to mitigate issues as they arise.[11] In stage 3, significant coordination requirements between transmission and distribution operations and DER aggregators drive the need to create a dedicated role in the operations organization with responsibilities of expanding, maintaining, and troubleshooting data integration with operational tools and systems. A core function of this role is knowing how to interpret and react to the information streams that comprise operational situational awareness.

Process

The evolution of situational awareness starts with visibility. Stage 1 involves expanding DSCADA deployments across a utility's substations as well as modernizing and refreshing operational displays to indicate all relevant grid assets, even if remote monitoring and control is not yet available. It is important in stage 1 to begin to recognize DER as a grid asset and include it on SCADA displays, even if it is just an icon for large standalone DER installations or a feeder attribute for aggregate penetration of small resources. Another vital process in stage 1 is developing and applying an alarm management philosophy to ensure that the most pertinent and actionable information is presented to operators. One aspect of situational awareness is removing unnecessary information (distractions), which is an overarching goal of alarm management.

Stage 2 involves a concerted effort to make use of the additional data streams available to the control center. DSCADA may still be expanding to reach line devices and some large DER installations. AMI and primary meter data are being brought into the control room. Updating standard operating procedures to leverage or reference the available data streams ingrains situational awareness into the operating mentality. One opportunity to utilize this data is to integrate it into on-line power-flow, which translates disparate spot measurements into an integrated grid health assessment. As these new data streams trickle into the control room and operational displays, practices for utilizing that data must be investigated and, where fruitful, exploited.

The final leg of situational awareness is developed in stage 3, where operators gain an understanding of behavior at the grid edge. Complementing an understanding of where the grid is operating in relation to its bounds, DER performance and availability complete the puzzle with a representation of available actions that operators can take. To put all these pieces together, a what-if analysis using real-time power flow or distribution system state estimation (DSSE) gives operators foresight into the expected conditions on the grid. This cannot be accomplished by operators alone and must rely on advanced analytical capabilities of a distribution management system (DMS) or similar tools.

Technology

The tools used to achieve situational awareness are present through all three stages of distribution system evolution, but are steadily fleshed out as the evolution unfolds. SCADA displays or other operational diagrams are the skeleton — the structure — of this capability. Real-time monitoring, starting at the substation and working outward along the feeder, provides feedback on where the system is operating within or outside its allowable limits. Feeding that monitoring into the load-flow functionalities of the DMS distills the vast array of information down to what is actionable. Finally, visibility of customer resources allows operators to understand where the grid is likely headed, and what responses are possible. The ability to run power-flow in real time or harness DSSE flips the perspective from what was or is happening to what might happen as a result of operator or customer intervention.

Capability Roadmap

Situational awareness, one of the building blocks of operational capabilities, will no doubt evolve alongside the opportunities for DER to provide services to the grid. Part of the challenge with situational awareness is striking a bal-

11 An alarm is an audible or visible means of indicating to the operator the presence of an equipment malfunction, process deviation, or abnormal condition requiring a response. *Distribution Control Center Alarm Management: Philosophy Guide.* EPRI, Palo Alto, CA: 2019. 3002015266.

ance between sufficient information and extraneous details. That is because data alone does not equate to situational awareness. Instead, data needs to be collected, analyzed, interpreted, and finally presented in order for it to be informative. Achieving this is no small feat, especially as the sources of data continue to expand. Therefore, the capability roadmap in Figure 4 portrays a sequence of intermediate outcomes resulting from a utility's projects and activities related to enhancing situational awareness. In this way, the roadmap is not a sequence of prescribed steps each utility should take, but a set of guiding principles against which a utility can plan its steps and measure the progress of its efforts.

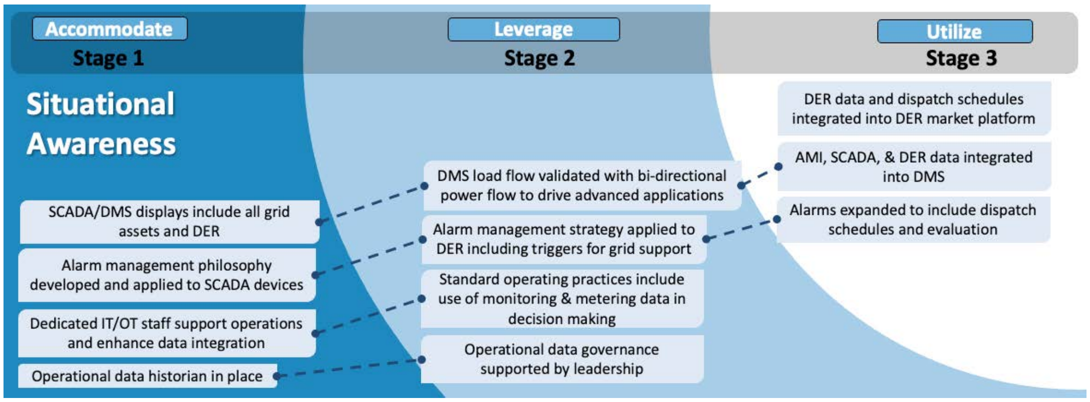


Figure 4. *Situational awareness capability roadmap*

Monitoring and Control

This group of operations capabilities involves real-time monitoring and control of traditional grid assets and DER to ensure reliability, efficiency, and safety. As the distribution system becomes more dynamic and complex, operators will need to rely on a suite of decision support and autonomous control systems such as smart controllers on grid and DER devices, adaptive protection schemes, DSCADA, DMS, and DSSE, and an automated analytical engine that pulls all of these technologies together. These systems must be integrated via distributed telecommunication systems and robust data governance and cyber security.

Considering the scale of distribution systems, this foundational capability will expand in coverage over time and will evolve in functionality as technologies mature. Expansion of monitoring and control capabilities will likely be part of a utility's grid modernization plan every year. Deploying smart technologies will require upskilling the operator position as well as augmenting the operations staff with expertise in telecommunications, IT, and cyber security. Table 2 provides an overview of the evolving people, processes, and technology that comprise monitoring and control capabilities.

Table 2. *Evolution of people, process, and technology for monitoring and control*

	People	Process	Technology
Stage 1	IT/OT/Field Support Staff	DSCADA monitoring of substation transformers, feeder breakers, and line reclosers	Smart Grid Devices, Telecoms, DSCADA
Stage 2	IT/OT Coordinator	DSCADA Monitoring of Line Devices, Aggregated AMI in DMS	AMI & Protection Data Management
Stage 3	Operational Data Sharing Coordinator	DER Aggregations Integrated In DMS	Enterprise DER Management Tools

Much of the focus of monitoring and control is on acquisition of data and delivery of control signals. In order to acquire data, utilities are first deploying smart field devices, which were either previously nonexistent or operated autonomously with local monitoring and control at the device. As DOE's framework posits that the evolution of the distribution system will include a shift toward monitoring and controlling DER, both utility and third party owned, the domain of connected devices will expand to include DER in addition to traditional utility assets and infrastructure.

People

In stage 1, there is a push for expanding DSCADA coverage to all substations with remote monitoring and control of substation transformers, feeder breakers, and some line devices such as capacitor banks and reclosers. This deployment involves a heavy lift by field staff to deploy assets and telecommunications infrastructure as well as IT/OT staff to integrate the data with back-office systems and operational tools. During this time, operators are being trained on the remote operation of substation and line devices, which may involve modifying standard practices and interactions with field support staff.

In stage 2, the deployment of smart grid devices, including line devices and sensors, expands from substations downstream to feeders towards the grid edge. Again, IT/OT support staff and field personnel carry out the infrastructure deployment while operators become fluent in the capabilities of the DSCADA system and the DMS. Adding to the set of monitoring data from the field is smart meter data, typically aggregated to represent the behavior of distinct segments of the customer population. With the volume of data sources and system integrations, there is cause to create a full-time role for operational IT/OT support and troubleshooting. In addition, staff with a system protection background may be needed to support the specific requirements of protection data management.

In stage 3, meter and monitoring data from DER is integrated into the DMS and other operational tools to provide better visibility of these assets. In addition to the monitoring aspect, some DERs require two-way communication to enable dispatch and control by operations staff. IT/OT support as well as staff with a familiarity with DER technology are needed to establish and verify communication to these devices. Managing DER may be beyond the scope of traditional grid operators, causing some utilities to create a dedicated role for a DER operator. There is also a growing need to leverage the growing volume of operational data outside of the distribution control room for tasks such as integrated system planning and coordinating with bulk system operators and DER aggregators. Systems integration and data management becomes a full-time role with a responsibility of coordinating the collection, management, use, and sharing of operational data.

Process

The process of attaining monitoring and control capabilities spans both the deployment of physical assets and communication infrastructure as well as the integration of those data sources and control capabilities into operational tools. These tools grow more powerful with each connected field device, in turn requiring operators with a masterful grasp on their use. Switching procedures and field crew interactions morph over time to become increasingly reliant on grid operators to manipulate the status and settings of field devices with the goal of streamlined and efficient grid operation. As more granular control is achieved, operators and operational tools need to leverage ever more granular monitoring data from individual or multiple meters in aggregate. As the need to manipulate DER emerges with an expanding set of program offerings, both the monitoring and control infrastructure extends beyond the grid into the customers and DER it serves. Existing processes for managing the grid again need to be modified to account for managed DER operation, and an entirely new set of processes need to be developed for monitoring and controlling these resources.

Technology

The technology used for monitoring and control consists of field devices and their controllers, sensors, metering equipment, communications infrastructure, and operational tools. A utility may have its own communications medium such as fiber, or it may rely on a suite of solutions catered to specific applications. Databases, operational data historians, and analog records are key components in this regard, as well as the end use systems and software used to display monitored values and enable control actions by operators. While a utility may have a chosen strategy for communicating with and collecting data from line devices and sensors, it will need to develop a communication strategy for connecting with DER. Because these resources may be owned or operated by external parties, both physical and cyber security are important considerations in selecting the appropriate technology solution.

Capability Roadmap

Monitoring and control are defined by data acquisition and the delivery of control signals. The shift in the operation of the distribution system – from the field to the control center – has been made possible by smart grid devices and a communication network to exchange data and control signals. With the evolution of the distribution system, the centralized, remote operation of the grid will expand from the substation outward to the grid edge. There are several possible frameworks for orchestrating the control of DER themselves, some with DER Aggregators interfacing between bulk system operators, distribution utilities, and DER, and others that envision the distribution utility as the primary facilitator of this role.[12] Whichever entity ultimately controls DER, operating the distribution system in the presence of DER providing services will require an expanding set of data sources and controllable devices or resources within the control center and beyond. The selection of line devices and sensors, communication infrastructure, and cyber security protocols, as well as control algorithms for a wide-ranging array of devices and resources are all building blocks of this critical function. The capability roadmap is displayed in Figure 5.

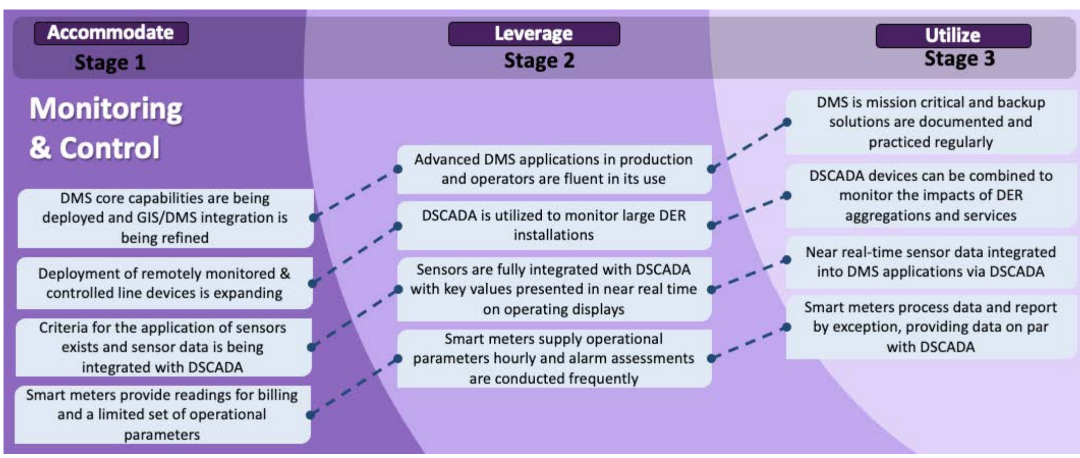


Figure 5. *Monitoring and control capability roadmap*

Outage Management

This capability area is specific to monitoring and managing the impacts of distribution system outage events to minimize customer disruptions and restore normal service as quickly as possible. It includes the use of Outage Management Systems (OMS) to efficiently manage outage events and coordinate restoration efforts. As technology matures and becomes available, the process leverages automation systems such as Distribution Automation (DA) and Fault Location, Isolation, and Service Restoration (FLISR) to detect, isolate, and restore service following outages. The process also encompasses contingency analysis to assess outage risks. Finally, as DER penetration increases to the point that impacts during contingencies become material (either positive or negative), DER must be considered in restoration as well as grid automation schemes. For example, after an outage it may be beneficial to bring DER online before load to support restoration and avoid impacts associated with cold load pickup.

Today the OMS typically assesses outage impacts based on "as-planned" feeder models and connectivity models that assume the only power source is at the feeder head within

12 Martini, P.D., L. Kristov, M. Higgens, M. Asano, J. Taft, and E. Beeman. "Coordination of Distributed Energy Resources; International System Architecture Insights for Future Market Design."

a substation. As grid flexibility increases, OMS will need to understand the actual "as-operated" configurations, including islanded operations if applicable. A more dynamic distribution system with multiple energy sources and variable circuit configurations will require enhancements to existing DA and FLISR automation schemes as well as OMS logic that monitors customer and DER interruptions. Finally, some DER services may be considered part of outage management, especially use cases such as leveraging energy storage and microgrid operations to maintain service to, or restore, as many customers as possible.

In addition to real-time operations, a critical component of outage management includes maintaining accurate reliability data for internal and regulatory reporting, as well as historical performance trending. Managing this important data set will require staff and processes to maintain data quality and produce timely and accurate performance reports. Table 3 outlines how people, process, and technology involved in outage management are expected to evolve.

Table 3. *Evolution of people, process, and technology for outage management*

	People	Process	Technology
Stage 1	Reliability Data Manager, IT/OT Support Staff	Breaker & Recloser SCADA Status Integrated w/ OMS	OMS, DSCADA, DA, FLISR
Stage 2	Upskilled Operators	OMS Leverages As-Operated System Model & DER data	DMS
Stage 3	Reliability Coordinator	OMS Tracks Microgrid Operation & DER Availability	Microgrid & DER Controllers

Often starting as an ad-hoc process reliant on institutional knowledge and simple spreadsheet-based tools, outage management is a cornerstone of maintaining and improving service reliability. As the evolution of the distribution system unfolds, identifying, responding to, and managing distribution outages will become more complex because distribution connected resources are not only consumers, but also providers of critical grid services. Like other capability areas, outage management provides a small window through which to examine the transition to a DER-rich future.

People

In stage 1, resources are focused on developing and integrating capable and accurate OMS that can filter both customer calls and AMI data to make accurate predictions about the source and scale of distribution outages. Beyond operationalizing this system, a dedicated role for a reliability data manager is needed to support after-the-fact event analysis and reliability reporting. Additional resources are needed from IT/OT support staff to collect and integrate data sources. Similarly, veteran operators who can piece together event records to monitor progress and derive reliability indices will support the reliability data manager.

Stage 2 involves operators with an expanded skill set, specifically in leveraging DA/FLISR systems to reduce outage durations and avoid sustained interruptions for as many customers as possible. IT/OT support staff are focused on furthering OMS capabilities to align with the as-operated state of the grid as represented in the DMS, as well as automatically dispatching crews based on predefined priorities. Reliability reporting expands beyond compiling indices to providing diagnostics on DA/FLISR mis-operation and trouble spots on the grid, requiring a balance of experienced operators and IT/OT staff familiar with the DA/FLISR technology deployed.

In stage 3, both the volume of, and opportunities for, DER may eclipse the capabilities of the reliability data manager who is responsible for quantifying reliability metrics and performing diagnostic assessments. The role evolves and expands into a reliability coordinator overseeing the coordination of DER to provide grid services, including aiding in restoration activities. The new reliability coordinator role facilitates advanced analytics for prescriptive reliability improvement projects, performance verification and settlement of DER services, and granular benefits calculation. The reliability coordinator role will encompass identification of impacted resources as well as developing action plans to leverage DER – even creating microgrids – to maintain or restore power to as many customers as possible.

Process

In stage 1, outage management processes are modernized through development of an OMS that considers customer calls, AMI, and breaker recloser status from SCADA to make accurate predictions about sources and locations of outages. Grid operators are trained on leveraging the OMS and validating outage predictions resulting from new data integrations. Operators will need to develop trust that automated DA/FLISR systems are capable and accurate enough to supplant prior practices that relied on situational awareness and operator intuition to respond to distribution outages. This aligns with an overarching shift toward remote operation of the grid through a DMS.

In stage 2, there is a push to quantify benefits from widespread deployments of DA and FLISR that are the target of grid modernization investments. At first this will be a manual process, but it will eventually mature into an automated approach. Additionally, the reliability analysis that once focused on deriving reliability indices will expand to include identifying and mitigating mis-operation of DA equipment as well as identifying opportunities to expedite restoration. Some of the mis-operations may arise as increasing DER penetrations begin to mask load; therefore, DA/FLISR algorithms are enhanced to incorporate DER measurements or forecast. With growth in DER, the OMS must also evolve to quantify the volume of DER impacted by any given outage. As both the DA/FLISR schemes and OMS are integrated with the as-operated model in the DMS, processes for ensuring model data quality are needed to ensure resulting accuracy and efficacy of both DA and OMS.

In stage 3, outage management and restoration activities are further broadened to include DER as a tool to be used alongside traditional assets and practices. Identifying the resources that are isolated due to an outage, as well as those that can be brought online to assist with restoration, is a new responsibility in the control center. Furthermore, it may be necessary to utilize distribution automation infrastructure to make topology changes that are beneficial to DER utilization, even when there is not an outage. An entirely new process will be incorporating microgrid operation into OMS and reliability calculations. Similarly, outage planning (or scheduling) must include consideration of maximizing service availability for both consumers and DER, up to and including forming islanded microgrids to maintain service during scheduled outages.

Technology

The technology used in outage management starts with an OMS that is integrated with both customer calls as well as breaker and recloser status from SCADA. As the DMS becomes operational and robust, the OMS and DMS are integrated to allow the full as-operated state of the grid to be an input into the OMS. Eventually, the utility's DER management tools are also integrated into the OMS. Reliability analysis and reporting may start as a fully manual process, but as the evolution of the distribution system unfolds this process becomes increasingly automated.

Capability Roadmap

Outage management is an essential capability for ensuring that DER remain connected to an energized grid and are able to provide services. As the management of the grid becomes increasingly digitized and automated, the OMS will need to remain integrated with an array of enterprise tools including DSCAD, DMS, and AMI. Another facet of outage management is improving reliability through automated restoration and even leveraging DER to support the grid or islands that form in the absence of utility provided service. Compared to spreadsheet based systems of the past, the vision for outage management is dynamic and robust. The capability roadmap in Figure 6 provides a progression of achievements resulting from advancement is outage management.

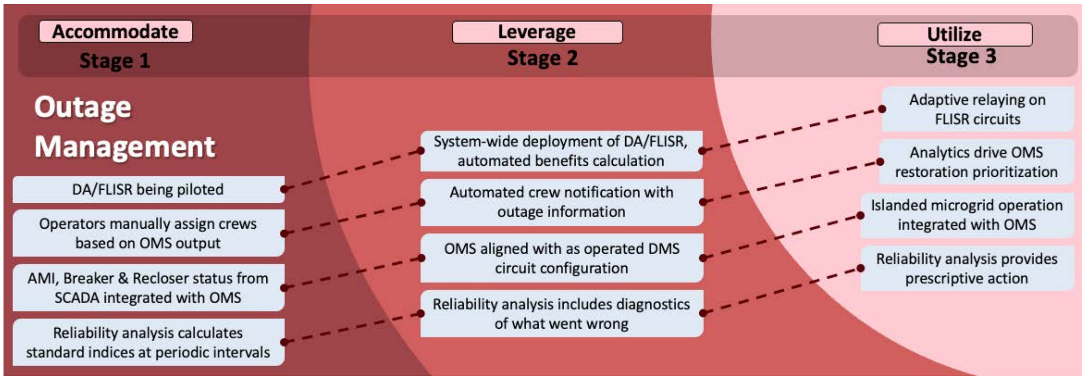


Figure 6. *Outage management capability roadmap*

DER Management

This group of capabilities focuses on effectively monitoring and modulating DER interconnected to the distribution grid. It includes activities such as controlling reactive and active power output, dispatching DERs based on grid conditions and market signals, coordinating DER services with transmission and distribution operations, managing demand response programs, and overseeing the operation of customer and utility microgrids. Additionally, it encompasses the development and implementation of operational practices and leveraging operational experience to optimize DER management.

DER may be utility or third party owned. A host of new roles and responsibilities within the distribution operations function will be required to coordinate DER services across transmission and distribution (T&D) operations with DER aggregators and an expanded array of stakeholders. Tools specifically developed to manage DER will be needed as management shifts from a hands-off, autonomous approach to an integrated, coordinated, and centrally managed approach. These tools may begin as stand-alone applications tailored to a specific DER service offering; however, as offerings expand an enterprise DER management system (DERMS) that supports multiple DER services will likely be necessary to drive process consistency and efficiency. Furthermore, a platform for communication and coordination accessible to distribution opera-tors, transmission operators, wholesale market operators, DER aggregators, and DER owners is needed to ensure that all stakeholders have visibility of expected actions. Depend-ing on the market rules governing DER services, appropriate standards of conduct will be required between grid operators and market participants.

Table 4. *Evolution of people, process, and technology for DER management*

	People	Process	Technology
Stage 1	IT/OT Support Staff	Supplementary anti-islanding is monitored by operations; occasional DER isolation for work & switching	Supplementary anti-islanding, utility owned switchgear, smart inverters
Stage 2	DER Coordinator	NWS are considered in operational planning with hardcoded dispatch schedules in DMS	NWS dispatch schedules integrated in DMS
Stage 3	DER Platform Manager	DER aggregations considered in operational planning; DER utilization is coordinated on a market platform	DMS integrated with DER management tools and common market platform

People

In stage 1, there are no widespread DER program offerings involving management or control, and DER operates autonomously with factory settings, the primary support role will be filled by IT/OT support staff and system protection to ensure that any DER requiring supplemental anti-islanding are integrated into utility communication and control infrastructure. Operations engineering support may modify SCADA and DMS displays to indicate the size, type, and location of larger DER, especially those with supplementary anti-islanding. These same large DER may be equipped with utility owned switchgear that operators can remotely monitor and control to maintain safety and reliability during distribution maintenance and outage restoration. Operators and field crews will need to be trained in proper switching, tagging, and isolation procedures specific to DER.

In stage 2, there is a shift toward actively managing certain DER, specifically those that have been planned as NWS to avoid, mitigate, or defer the need for capital investments. While these DER are considered managed, distribution operators are not directly responsible for their dispatch. Instead, distribution planning and operations engineering support, or the emerging operational planning role discussed below, serve as interim DER coordinators responsible for programming dispatch schedules and setpoints into the DMS or standalone DER management tools. As opportunities for DER to provide services to the bulk system emerge, the DER coordinator role also ensures that the distribution operations group is aware of coordination flows and exchanges with the wholesale market operator, DER aggregators, and DER owners.

In stage 3, pervasive opportunities for DER to provide services both to the distribution system and bulk power system require a permanent role for a DER platform manager. The volume and frequency of DER dispatch, as well as the multifaceted use cases that span multiple grid domains and time-frames,[13] cannot be managed by *grid* operators alone, instead pointing to a dedicated utility role with the sole focus of coordinating the operation of DER across a range of stakeholders.

13 Operational time-frames include week-ahead, day-ahead, near real-time, and real-time.

Process

Throughout the distribution system evolution, processes for managing DER shift from accommodating the autonomous operation of DER to leveraging specific, to planned DER for prescribed use cases, to broadly utilizing DER for an array of grid services. In stage 1, DER management is accomplished through monitoring and visibility, as potentially adverse impacts are identified and mitigated during interconnection study processes and resulting infrastructure investments made by the utility, DER developer, or DER owner. Operators will rely on supplementary anti-islanding or utility owned switchgear to isolate DER as necessary during switching, maintenance, and outages.

In stage 2, scheduled dispatch of NWS enters the operations organization. At first these DER may be manually dispatched, but some are eventually integrated into the DMS or standalone DER management tools. Operators rely on schedules and operating criteria developed by distribution operational planning.

Stage 3 sees a shift to coordination as a primary component of managing DER. As there are a variety of use cases and stakeholders involved, ensuring proper coordination and dispatch cannot be accomplished in an ad-hoc manner. Instead, the widespread use of DER requires the development of a common coordination or market platform that allows all parties to exchange information and maintain transparency. Distribution utilities play a vital role in the coordination process by ensuring that all parties are aware of constraints on their system and all available DER are leveraged to the extent possible to provide grid services.

Technology

The tools and technology used for DER management begin with visibility and reliance on customer owned equipment to supply anti-islanding protection. As more and larger DER interconnect to the system, utilities will deploy supplemental anti-islanding as well as remotely operable switchgear to streamline work practices and ensure field crews remain safe in the presence of DER. As NWS penetrate the system, the DMS or standalone interfaces to specific DER are populated with dispatch schedules and operating parameters. When multiple service opportunities arise in stage 3, a shift toward centralized management and coordination is needed. The DMS, DER management tools, and a DER market platform are integrated to make orchestrating the dispatch of DER more efficient.

Capability Roadmap

Central to the provision of DER services is the ability to manage DER, both to realize a benefit and avoid a conflict. Today, with static interconnection practices, DER management is generally limited to up-front programming of equipment settings, if they are used at all. In order to accommodate the volume of DER that are needed to effectively deliver services to the grid, utilities will need to develop communication and control interfaces to DER, which could be routed through DER aggregators. This vision is a paradigm shift for distribution operations, where it was once safely assumed that planning and interconnection departments would ensure that the autonomous operation of DER would not interfere with the operation of the grid. The capability roadmap presented in Figure 7 paints a picture of the steps that are needed to DER management with the operation of the distribution system.

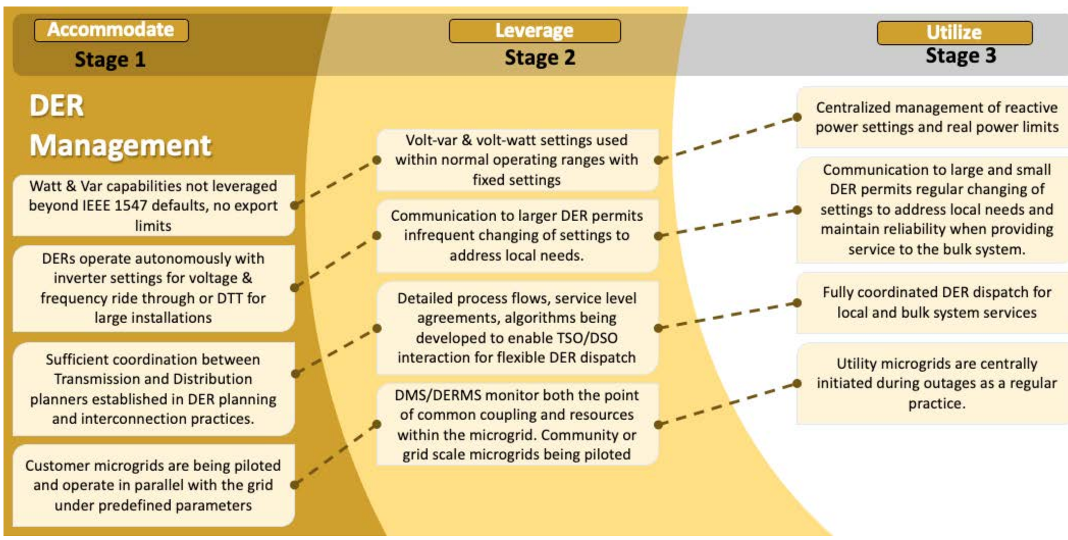


Figure 7. *DER management capability roadmap*

System Optimization

This category involves optimizing distribution grid operations to improve efficiency, reliability, and performance. It includes applications such as Volt-VAR Optimization and Conservation Voltage Reduction to optimize voltage levels for objective functions such as loss minimization and end-use energy conservation, as well as circuit reconfiguration to optimize power flow and restore power in an automated fashion. To enable these applications, granular operational forecasting in near real-time will be necessary to anticipate load and generation patterns, and grid modeling and analytics will be needed to assess expected performance and identify steps to improve on key performance metrics.

Operations will manage the distribution system considering load profiles and will also actively manage DER (both utility and third party) to maximize utilization and performance. The integration of multiple field devices will require robust telecommunications and the technical staff to manage the instruments and controls. Table 5 describes the evolution of people, process, and technology that define system optimization.

Table 5. *Evolving people, process, and technology for system optimization*

	People	Process	Technology
Stage 1	IT/OT Support Staff	Power Factor Correction, Loss Reduction	System Level Forecasts, Local VVO/CVR Control
Stage 2	Upskilled Operators & Forecasters	Energy Conservation, DER Coordinated var Management	Local Hourly Forecasts, Hybrid Control
Stage 3	Economic Dispatch Scheduler	Maximize DER Availability, Economic DER Dispatch	Granular Forecasts, DER Integrated VVO/CVR

People

System optimization takes root in stage 1 in the form of expanded grid management. Where previously the grid was designed and built to stay within operational limits with limited intervention, load growth and changing end use behavior require a more actively managed grid. The management of substation load tap changers, feeder voltage regulators, and switchable capacitor banks to keep the grid operating within its limits is part of a growing set of responsibilities in the control room. Similarly, deployment of remotely operable switchgear allows operators to isolate damage and restore service to more customers sooner. A precursor to operating these assets is the establishment of communication. Field crews will be needed to install line and substation devices, IT/OT staff will set up data integrations, and system planning may be involved in developing appropriate settings groups (e.g., bandwidth, delay, trip curve, etc.). At first, these devices may operate with local controls fed by local measurements such as voltage, time of day, and temperature, requiring minimal guidance and diagnostics from operators.

In stage 2, system management transforms into system optimization. The operator role includes not only maintaining the system within its limits, but also making fine adjustments to operate the grid within a narrower, optimal set of bounds intended to achieve objectives such as minimizing technical losses or reducing energy consumption of end use loads. Operators must be keenly aware of the status and health of voltage and var regulation equipment as they operate the grid for maintenance and outage restoration. Advanced capabilities of the DMS begin to drive the operation and optimization of line devices, and operators must be trained to proficiently leverage these capabilities. Part of the success of these applications relies on forecasts that are generated at a local resolution with daily and hourly granularity, often requiring a dedicated staff, such as an operational planning role, to build and develop these forecasts.

In stage 3, the set of devices used to optimize system performance grows to include both customer and utility owned DER. Because the use of these DER may incur an operating cost, system optimization now includes an economic component and thus a role for making cost-based scheduling decisions. Merging DER into system optimization increases the complexity of operational and control decisions. IT/OT staff are still a critical resource in the control center, as are support staff skilled at the inner workings of DMS and DER management tools. Forecasting requirements continue to grow as well, including load and DER, both of which are increasingly difficult to predict as resources are dispatched instead of following predictable weather patterns such as solar irradiance. The forecasting role may expand to a group or organization to keep up with the demands of the grid and the technology used to manage it.

Process

The evolution of system optimization can be described as a continual refinement. Stage 1 involves leveraging line devices to help maintain the grid within operational limits as the risk of excursions grows. Once processes have been standardized for operating within those limits, narrower targets are established requiring more granular adjustments and fine tuning of line devices. In stage 2, achieving precise operational objectives requires local, hourly forecasts and more complex control algorithms to be developed. Regulation equipment cannot produce the desired performance using local measurements or hardcoded schedules alone and must be coordinated with hierarchical control. In stage 3, system optimization evolves from selecting the appropriate settings for a fleet of utility assets to optimizing technologies and economics with reliance on third party resources. Moreover, some objective functions will be in opposition to one another (loss reduction, VAR optimization, and mitigation of both low and high voltages at the end of the feeder), which may not be possible with the solutions available today. All of these process changes are intended to move service delivery from sufficient to favorable to ideal.

Technology

System optimization is realized through voltage and VAR regulation equipment, telecommunications and control hardware, and advanced applications and algorithms. The existence of regulation equipment is a foundational requirement that communication and control capabilities enhance for more nimble and granular optimization. Forecasts are part of this technology, enabling the transition from reactive control to proactive control and scheduling. DER that can modulate distribution voltage (and reactive power) are added to the list of regulation equipment, even though they may not be owned by the utility. Control systems and decision logic that incorporate both technical and economic factors also help optimize the system.

Capability Roadmap

System optimization is a relatively new capability within distribution operations, having evolved from increasing scrutiny over electrical losses and customer reliability. As DER penetration grows some grid optimization problems may be challenged by these new resources, while others stand to benefit from them. In order to continue increasing the efficiency and quality of service delivery with DER, those resources will need to be integrated into optimization algorithms and may even be controlled to enhance the objective function. Figure 8 shows the needed advancements across the evolutionary stages.

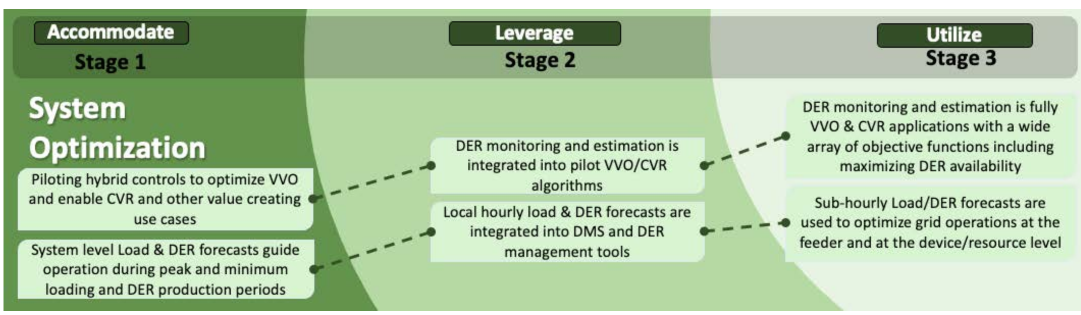


Figure 8. *System optimization capability roadmap*

Operational Planning

This group of capabilities focuses on developing and implementing near-term operational plans. It includes development of granular (temporal and spatial) load and DER forecasts and applying those forecasts in grid models to determine necessary operational actions (switching, voltage regulation, DER dispatch, etc.) to achieve operating expectations. This capability ensures that the distribution system operates effectively under normal conditions and is prepared to respond to contingencies and emergencies.

Operational planning has been relatively limited within distribution operations, because utilities traditionally built distribution capacity to meet annual peak load and unmanaged DER. For many utilities, operational planning will be a major new capability built from scratch. This function may begin simply with an experienced operator acting as an outage coordinator. It will likely need to expand and mature into a dedicated functional group within distribution operations requiring engineering staff, data scientists and analysts.

Table 6. *Evolving people, process, and technology for outage management*

	People	Process	Technology
Stage 1	Outage Coordination	Historical peak load data, tabular load assessment, and ad hoc stakeholder communication	Ad-hoc spreadsheets and databases
Stage 2	Load & DER Forecaster, Operations Engineer	Daily operational forecast of load and DER, short-term studies in load flow tools	SCADA Historian, Forecasting Tools, Load Flow & DMS
Stage 3	DER Market Liaison	Maximize DER Availability, Economic DER Dispatch	DERMS, DER Market Platform

People

In stage 1, operational planning largely consists of outage coordination and ad-hoc engineering support during peak loading or abnormally constrained conditions. Because of the numerous projects and initiatives that fall into the category of grid modernization, there is a growing workload for this role. For example, distribution automation increases reliability through efficient and automated feeder switching, yet configuring and maintaining the integration of field devices with SCADA, DMS, and OMS is a new task that did not exist prior to the deployment of DA. In the past it was manageable for night shift operators to draft and review switching orders and perform certain aspects of outage scheduling, but the volume and complexity of construction, repair, and grid modernization projects soon requires a dedicated role. This role can be filled by a seasoned operator with occasional support from distribution planning or operations engineering.

In stage 2, the volume and frequency of engineering support necessitates embedding a capable engineer within the control room full time to routinely verify switching arrangements and create near-term action plans in response to changing conditions. A reactive position is not feasible. Instead, it requires staff well versed in the creation and use of local forecasts to make informed decisions about switching that is both underway and planned for the near future. These tasks also require experience and proficiency with load flow analysis tools, using either the platform applied for distribution planning or DMS capabilities.

In stage 3, the operation of the grid needs to be commensurate with managing high DER levels. Key aspects of distribution operational planning include maintaining visibility of wholesale market operation, coordination with market operation, and managing DER for distribution needs — in addition to continued responsibilities of outage scheduling and engineering support. The myriad of program offerings and uses cases for DER grow, possibly requiring a dedicated facet of operational planning focused solely on DER. Part of this role will be a distribution liaison to wholesale markets. Other aspects will focus on coordination of DER for distribution use cases.

Process

In stage 1, a primary focus of operational planning is scheduling outages and approving switch orders to minimize disruptions to customers while providing a safe working environment for field crews. This mainly involves identifying switchable arrangements that allow work to occur while still serving as much load as possible. Technical support for loading capability and protection coverage occurs infrequently and falls into the domain of engineering support on an as-needed basis.

In stage 2, the frequency of support requests to organizations outside the control room increases to the point that operational planning absorbs a dedicated position for engineering support. As advanced applications such as volt-VAR optimization, FLISR, and fault location come online, the operational planning role will be responsible for ensuring those functionalities meet design specifications and are operating successfully. One of the new processes for this role is developing near term forecasts for operational planning studies and visibility for grid operators. These forecasts include load and DER and are built using both bottom-up meter aggregation as well as top-down load and weather data.

In stage 3, DER are added to action plans developed by operational planners. Operational planning includes processes for verifying that planned services will not impact reliability and identifying needs for distribution services on the operational horizon. Coordination requirements between a variety of stakeholders (e.g., bulk power system operators, DER aggregators, customers, DER owners) necessitate well-orchestrated interactions on behalf of the distribution utility, something that is expected to be a component of operational planning.

Technology

Historically, operational planning leaned heavily on system models or maps as well as ingrained knowledge of the grid (seasoned operators and field crews) to identify feasible switching arrangements for planned work. As technical challenges grow, utilities leverage load flow and protection analysis tools to assess emerging conditions and draft remedial action plans. As the evolution of the distribution system unfolds, the timelines for completing near term studies and making action plans shrink to a state where load flow and other analysis tools must leverage as-operated models of the distribution system. Finally, active management of DER participating in wholesale markets as well as distribution-programs requires both dedicated internal DER management tools as well as integration with external systems from wholesale market operators, DER technology vendors, and DER aggregators.

Capability Roadmap

Operational planning is an emerging role in distribution operations for many utilities,[14] driven by the strain of an aging grid saturated with load and experiencing growing DER.

From modernization efforts that improve reliability to the advent of opportunities for DER to participate in wholesale markets, the complexity of the distribution system continues to grow. This new role, filled by staff with diverse skill sets that are competent in both operational duties as well as advanced analytics, will only expand and mature with the evolution of the distribution system. Operational planning, which consolidates the existing near term planning needs in the control center with future tasks of identifying and capitalizing on opportunities for DER to support the grid, is steadily becoming paramount to the success of distribution operations. The capability roadmap depicted in Figure 9 describes the advancement in operational planning activities throughout the evolution of the distribution system.

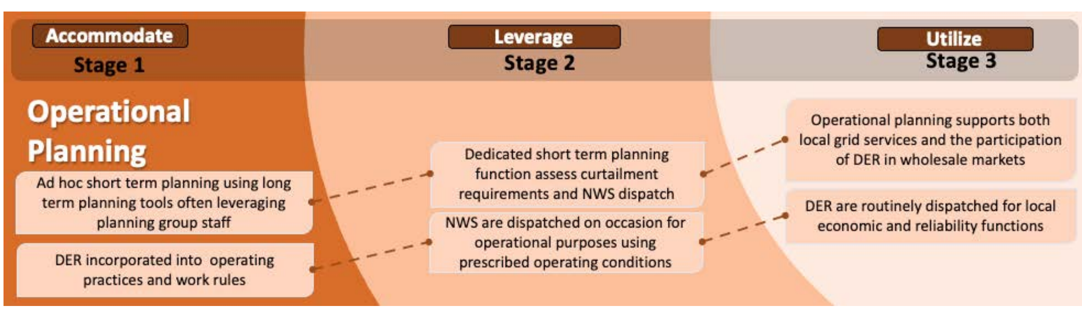


Figure 9. *Operational planning capability roadmap*

14 *Distribution Operational Planning: Expanding the Capabilities of a Modern Control Center*. EPRI, Palo Alto, CA: 2022. 3002024512

Roadmap Summary

Tackling enablement of DER services within the distribution operations group is a challenging exercise. By breaking an organization into its functional roles and associated capabilities, as the roadmaps in this paper illustrate, it is possible to examine changes needed at a granular level. Describing changes in terms of people, process, and technology provides additional context to the scope and scale of modifications required, informing strategic decisions around hiring, investments, and organizational change management. While investigating changes on a capability-by-capability basis is needed to explore all facets of the distribution system evolution, a strategic plan needs to recognize the *cumulative* scope and scale of investments required. A cohesive description of the impacts to people, process, and technology, across all capabilities, provides such a perspective, as the following figures demonstrate.

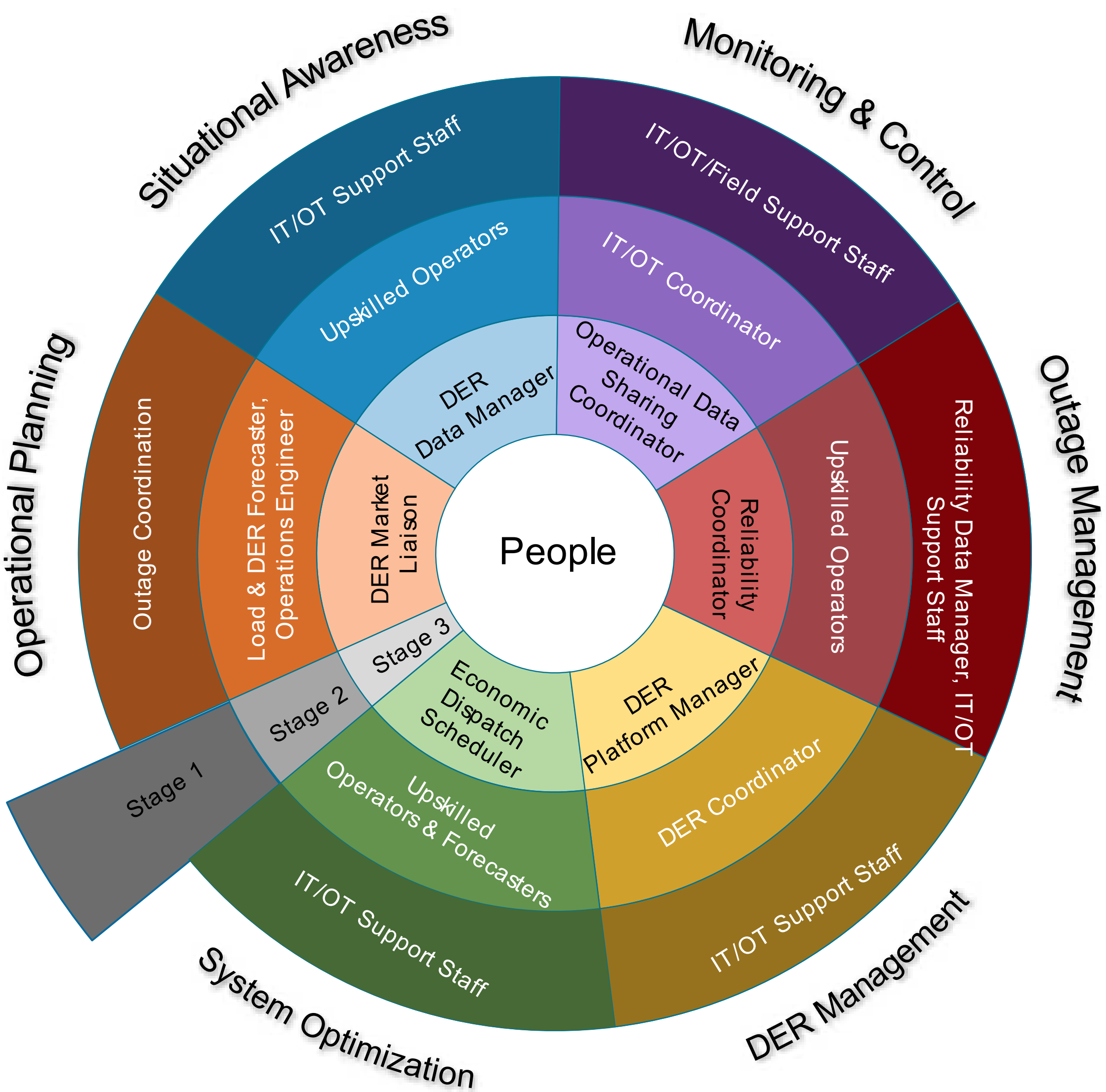


__Figure 10.__ Evolution of roles in the distribution operations organization

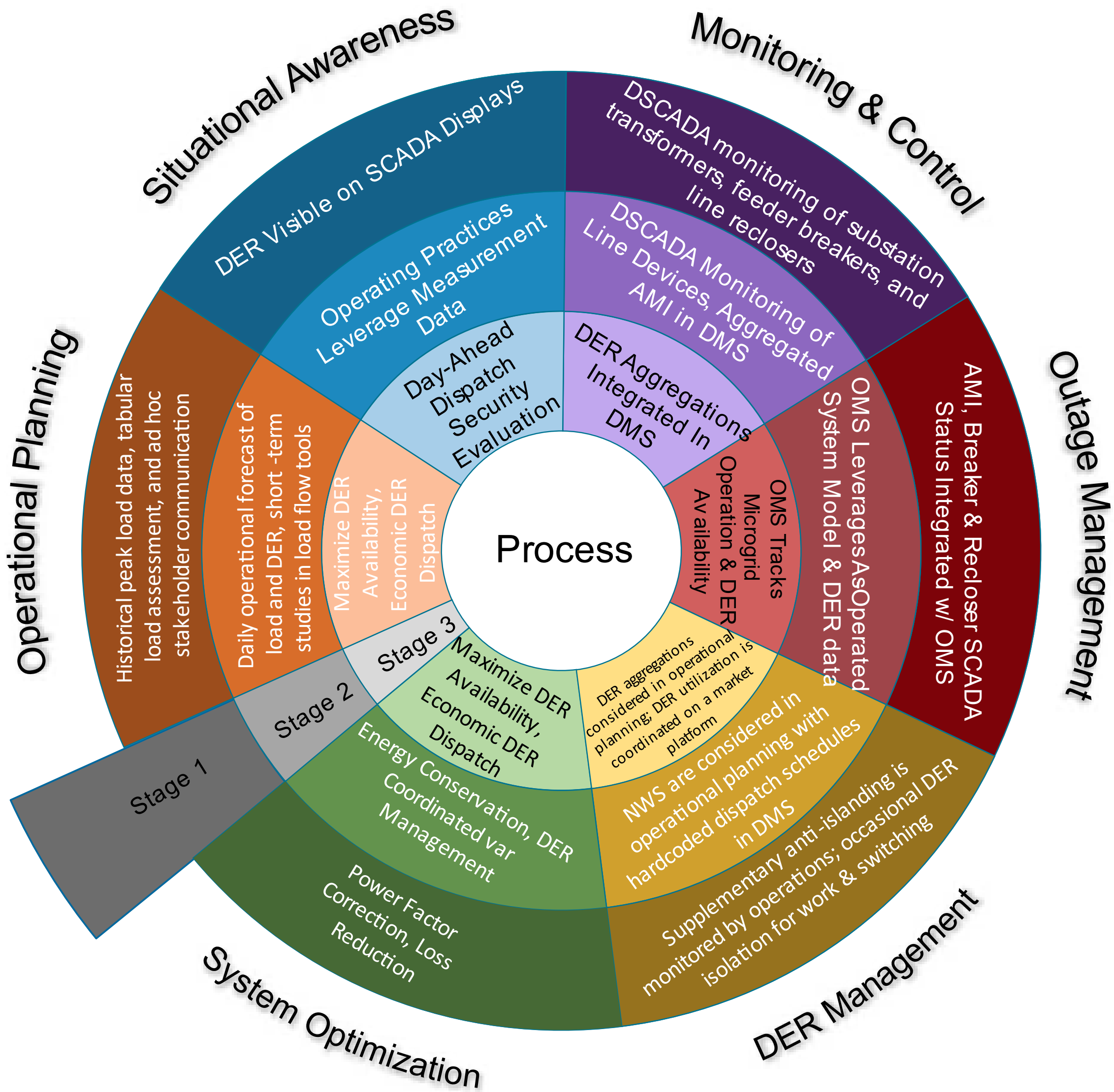


Figure 11. *Evolution of operational processes*

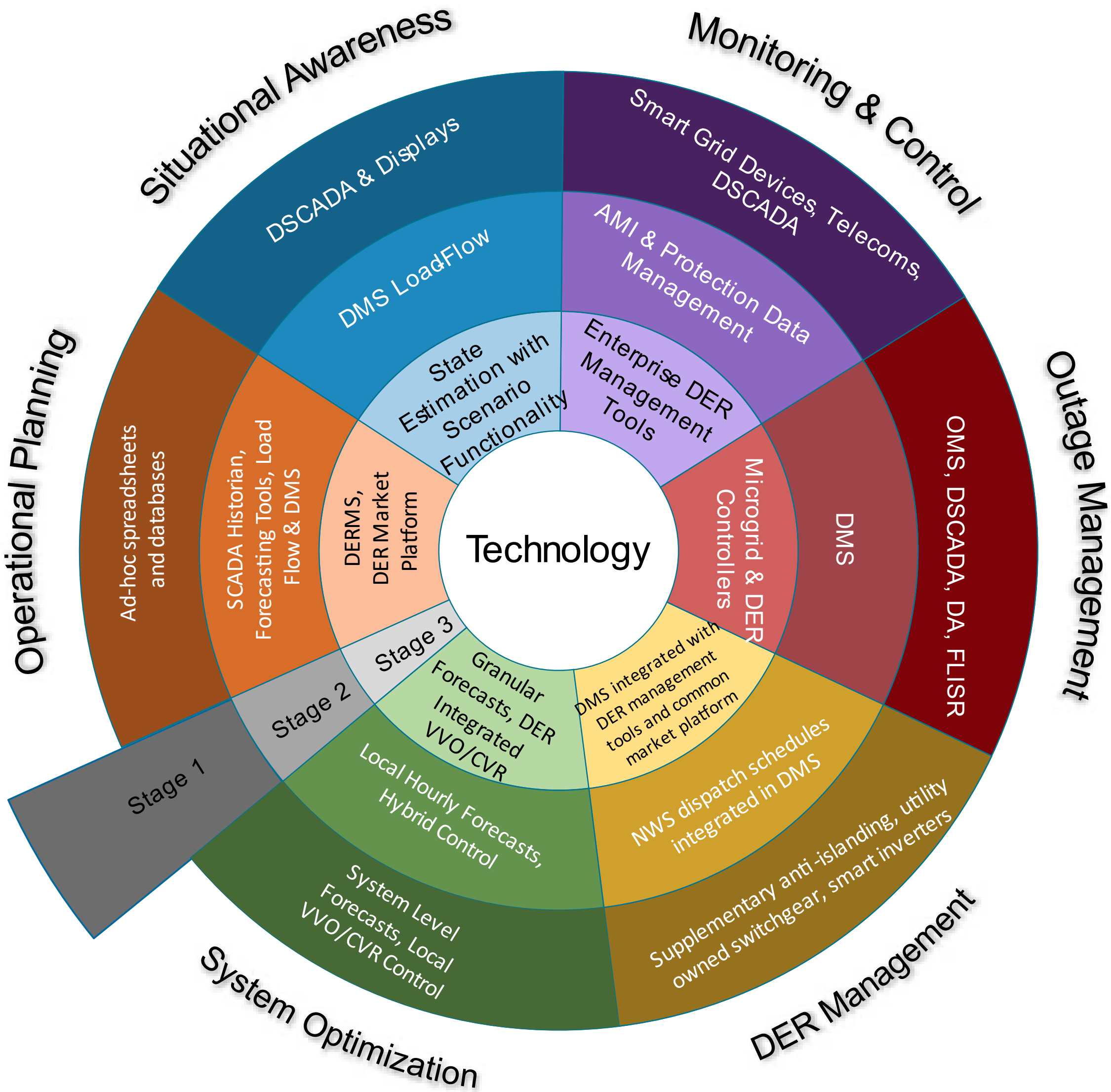


Figure 12. Evolution of technology in distribution operations

FOUNDATIONAL INVESTMENTS

The evolution of the distribution system, described by the capability roadmaps in this paper, will require investments in people, process, and technology. While this paper provides a clear picture of capability advancements needed, there are uncertainties and risks of investing in a 'field of dreams' on the distribution system. Some investments, such as enterprise DER management tools or DER market platforms, can only be justified when the opportunities – and more importantly, participation rates – rise to the level where prior solutions and technologies are incapable, uneconomical, or both. The result is that utilities cannot wait to act until a need exists in the present, and instead must judiciously act on the anticipated needs of the future.

Given this paradigm, it is pragmatic to identify the investments that are needed within each stage, and especially those that provide a foundation for future capabilities. This set of foundational investments needs to strike a balance between meeting the needs of the current distribution system and preparing for the needs of the grid of the future, all while remaining cost-effective. In some cases, selecting the least cost solution for today while disregarding the capabilities required in the future may result in stranded assets or incur costs of replacing obsolete technology earlier than expected. Conversely, investing in people, process, or technology for which an emerging use case is not certain poses a financial risk if those use cases fail to materialize. A staged investment strategy is needed to minimize the risk of either of these scenarios while still advancing capabilities to enable DER.

The capability maturity models and roadmaps presented in this paper point to investments that are needed for a utility to advance across capability areas. Within the spectrum of options, it is possible to identify the core set of foundational investments that support multiple capability areas, both within each stage and across stages. It is also important to consider investments in people, process, and technology as a spectrum, much like a capability. A DMS, for example, can range from a platform combining basic grid models with DSCADA monitoring and control all the way to an advanced optimization engine capable of driving multiple applications including DER dispatch. Similarly, IT/OT support can be provided by contractors or a dedicated utility organization with internal management, or anywhere in between. Therefore, each foundational investment needs to be explored to find the best fit – and least cost – for the needs of today and the capability to support future investments.

The following sections describe foundational investments across each of the evolutionary stages. Included are details on the goal of each investment within the current stage, as well as considerations for future enablement.

DSCADA

Distribution SCADA forms the connection between the control center and the external world of breakers, reclosers, sectionalizers, capacitor banks, regulators and line sensors. This linkage brings monitoring data into the control center and sends control signals to field devices — a hallmark feature of a modern grid. It is a prerequisite for making proactive operational decisions and enables the centralization of both system optimization and DER management. Moreover, DSCADA is both an integral and supporting technology in each of the capability roadmaps discussed in this paper.

At many utilities, transmission SCADA first provided some visibility to substations before distribution SCADA (DSCADA) was established. Utilities in stage 1 may still rely on transmission SCADA at some of their substations. However, as the operation of the grid has shifted from the field into the control room, distribution utilities have been steadily expanding the footprint of their DSCADA networks, especially in urban areas. Eventually, DSCADA will need to be deployed at all substations and downstream into the feeders themselves to provide monitoring and control capabilities for an array of devices and sensors.

Some utilities have not planned to deploy DSCADA beyond substations, or at all, and instead plan to rely on grid assets controlled by local measurements and logic. While this practice can support some level of system optimization and automated restoration, those functions are ultimately limited by what local measurements and hard-coded logic can provide. Because the cost of deploying or redeploying DSCADA is quite high, planning for future capabilities can help to minimize long term costs, even if near term costs are higher at the onset.

Widespread deployment of DSCADA down to line devices is not required in stage 1 and may only be complete across a utility's footprint in stage 3. However, it remains important to begin this deployment in stage 1 because several capabilities depend on this technology. This suggests that a staggered deployment with expansion both geographically and from the substation down to individual feeders may be an appropriate strategy for many utilities.

Smart Grid Devices

In addition to DSCADA, an array of intelligent electronic devices or smart grid devices are key ingredients for the future distribution system. These devices can be integrated with the DSCADA system to enable remote operation and control, facilitating the centralized management and optimization of the grid. While the devices themselves provide functionality such as voltage regulation, system protection, and operational flexibility, the additional visibility they provide greatly enhances situational awareness.

Like DSCADA, a fleet of smart grid devices across a utility's service territory is a substantial investment that will likely take years to complete. In addition to the financial costs, there can be significant technical debt incurred in the deployment of smart grid devices. This technical debt includes factors such as data management, alarm configuration and rationalization, as well as training for the operators and field staff that interact with these devices on a day-to-day basis. Beginning the deployment in stage 1 and continuing throughout stage 2 and possibly stage 3 spreads these costs into manageable pieces and allows a utility to start building additional capabilities that are dependent on these devices.

When developing a technology strategy around smart grid devices it is important to consider not only the devices themselves but the systems and software that they integrate into as well. Early control algorithms may leverage distributed logic without much coordination between devices and feeders, limiting the need for a highly capable DMS or other centralized control hub. Over time, as applications become interdependent and consider DER with multiple use cases, smart grid devices may need to be managed through centralized means to enable greater asset utilization and optimization. Planning ahead for the expansion of capabilities and functionalities that are achievable with smart grid devices – and the systems they integrate into – is one way to hedge against obsolescence and the need to replace devices before the end of life.

IT/OT Staff

Integrating both DSCADA and smart grid devices into the control room will require a core group of support staff to ensure that devices and communication networks are functioning properly and operationally secure. Additionally, this team will manage data integration into enterprise systems including data historians. A key consideration in this regard is to collect and store relevant data beyond what is required to operate the distribution system with smart grid devices in stage 1. Operational data that may be irrelevant with fewer connected devices and straightforward objective functions will eventually be a critical information source for operational planners, forecasters, and DER managers. Planning for data use cases beyond the minimum viable product, though more costly upfront, eases the transition to more mature capabilities in stage 2 and beyond. Therefore, the resource needs for IT/OT staff that will facilitate DSCADA and smart grid device integration extend beyond commissioning and into management and governance, making it worthy of consideration as a foundational investment.

Distribution Management System

The control systems and operating environment for distribution control centers continue to evolve toward a fully integrated and fully connected platform that is commonly called a distribution management system. Operating the distribution system with a model-based DMS is a central pillar of expanding the capabilities of the modern distribution control center. The traditional one-line displays common in many control centers offer some degree of situational awareness but stop short of providing 'what if' type analyses. The changing landscape of the distribution system is driving the need for applications driven by advanced analytics to be integrated into daily operations. Having access to a powerful, interconnected DMS lays the foundation for the processes and tools that will be required in stage 2 and 3.

While a DMS is posited as a necessary technology in stage 2, the planning, deployment, and implementation timelines for this technology can stretch to a decade or longer. Therefore, successfully realizing the benefits of a DMS in stage 2 requires foresight and planning in stage 1. A necessary step in this planning process is prioritizing the creation and ongoing maintenance of distribution system models. To effectively achieve this goal, collaboration is needed between the data producers and managers (GIS professionals), data consumers (operations, planning, asset management engineers), and the vendors that supply the platforms and tools connecting those organizations.

After completing the preparation steps in stage 1, DMS deployment will require operator training, as well as the creation of a dedicated team of specialists to support its operation. This team will be engaged in maintaining both distribution models as well as integrating the growing set of data streams from DSCADA, metering infrastructure, and supplementary inputs such as forecasts, load shapes, and eventually DER dispatch plans. Standing up a DMS does not happen without growing pains, and this transition is a multi-year process for most utilities. As with any analog to digital transition, creating – and rehearsing – backup plans for loss of communication or functionality is a critical aspect of DMS deployment. Additionally, the cyber-security aspects of interfacing utility systems to grid edge devices through communication networks must be addressed.

Like DSCADA and smart grid devices, DMS deployment can be viewed as a staged process, focusing first on core capabilities and eventually layering additional functionality as the people, process, and technology involved become mature. During stage 1, focus is on deploying DSCADA and creating interfaces to the DMS, developing and validating operational models, and training operators in the use of core functionalities including online power flow, state estimation, and new procedures for remotely operating field devices. It is likely that entire groups of standard operating procedures will need to be reviewed, revised, and socialized during this process. These include switch order management, situational awareness, and operational decision-making, which can impact groups beyond the control center. In some cases, there can be strong resistance to these changes, especially from field personnel when it comes to automated switching and restoration. In this regard, institutional buy-in and support up to the executive level are needed to ensure that the transition to centralized, remote operation is efficient and effective.

Grid Model Data Management

The central components that enable a DMS to provide value to the control center are a well maintained and accurate grid model[15] as well as the DSCADA communication infrastructure and suite of smart grid devices that are managed by the DMS. However, operators alone cannot be responsible for building and maintaining these models, a process that entails the integration of multiple corporate data systems including GIS, CIS, as well as the billing/meter data management systems. Instead, the control center will need specialized resources with a strong background in both modeling and enterprise systems so that the next generation grid models can be constructed, refined, and applied.[16] Some of these might be planning staff with experience in verifying and validating system models, as well as systems engineers with a background in data exchanges and integrations. Because one of the primary responsibilities of distribution operational planners will be creating and maintaining grid models, they will also be key resources for operators applying the models in the management of a complex grid.

Operational Planner

There is no doubt that the ability to perform system analyses will become a central component of the modern distribution control center. Built on a foundation of high-fidelity models and accurate forecasts, one of the core capabilities of the DMS is a suite of powerful distribution system evaluation tools. However, many utilities are in the early stages of adopting a DMS, and still rely on tools designed for planning applications to address operational challenges. The deployment of advanced DMS presents the control center with the opportunity to perform 'what if' analysis at a moment's notice, where they once relied on planning and protection engineers with a longer turnaround time. Quick answers to questions that measurement and sensing alone cannot answer gives the control center the independence needed to operate the grid more efficiently and effectively than ever before.

15 *Distribution Management System: Requirements Reference.* EPRI, Palo Alto, CA: 2017. 3002011003.

16 *Enhanced Grid Modeling: A Collaborative Framework for Model Verification, Validation, and Quality Tracking.* EPRI, Palo Alto, CA: 2021. 3002021521.

The ability to complete distribution system assessments accurately and in a timely fashion is a hallmark capability of operational planning. While the DMS is certainly an operational tool, operators will not be the only users. It is likely that a diverse team of operational planners, with backgrounds in planning, distribution engineering and automation, and system protection, will support system operators by performing a wide variety of studies that span the day-ahead, just-in-time, and post event analysis time frames. With increased visibility and situational awareness stemming from grid evaluations, operators will be able to better manage changing load conditions, make informed decisions when contingencies arise, and optimize the use of available assets better than ever before.

An electric distribution company's traditional planning and protection studies typically evaluate the grid under normal, as-built configurations. This practice extends to DER interconnection, which typically examines worst-case conditions on the primary configuration, and therefore, recommend that large DER go off-line during abnormal operation. However, the distribution grid is frequently reconfigured to accommodate maintenance, construction of new facilities, or address other short-term needs.

Many of the changes underway on the distribution system will require analytical capabilities to execute studies with a focus on near term or operational outcomes. While these studies differ from those traditionally performed by dedicated planning departments, there is significant opportunity to borrow from the skill sets and experience embodied by system planning and integrate those qualities into the control center.

The results of distribution assessments will be critical to informing distribution and transmission system operations when preparing for deliberate actions and responding to emergent issues. The ability to use high fidelity system models to evaluate current and forecasted conditions furnishes accurate details about the constraints and flexibility of the system, leading to a more nimble and responsive operational stance. In turn, distribution system operators have the confidence to create and execute action plans that maximize the use of grid assets while maintaining exceptional service quality and reliability for all customers.

In stage 2 and 3, the operations group will be asked to implement a DER dispatch plan from the transmission system operator or regional transmission organization/independent system operator. How will operators be prepared to determine if the dispatch plan is able to be supported by the distribution system? The analytics developed for scenario and strategic planning will need to be embedded into DMS algorithms to allow on-the-fly optimization of network configuration and DER/demand management. Even if technical and analytical solutions exist to support this decision process, the distribution operational planner will be responsible for preparing an array of action plans to support a more dynamic and DER reliant grid.

Enterprise DER Management

Interest in how DER can be integrated with utility operations for monitoring and management purposes tends to grow commensurate with the proliferation of these resources. DER integration with utility grid management system is challenging in that the number of devices can be high, the types of devices are diverse, and ownership may include customers, third parties, and utilities. In stage 1, DER integration and management involves identifying and standardizing the functions that individual DER can perform autonomously, in a distributed manner. Device-level functions like voltage ride-through, volt-VAR, frequency-watt, and dynamic reactive current were designed and documented and are now supported by communication standards and grid codes worldwide, making grid-supportive capabilities mandatory for new interconnections. While suitable for stage 1, device level functions are not sufficient to support provision of end-to-end organized services that emerge in stage 2 and become part of daily routines in stage 3.

DER management tools may initially be as simple as spreadsheets or databases used to track DER interconnections over time. Individual DER requiring infrequent settings changes might be accomplished manually, but this practice is not scalable or efficient to manage in real time. Due to the dependence of DER management on related grid support and management tools that exist in a DMS, at some level an enterprise DER management platform is the only logical solution for widespread and real-time DER management. This technology bridges the gap between grid management and DER by taking the complex capabilities of many DER and presenting them as a simpler more manageable set of services.[17]

A pragmatic consideration in planning and deploying DER management tools is developing standard interfaces. Due to the large number of resources, resource managers, and interfaces in the DER integration space, bespoke integration is not feasible outside of initial demonstration projects. In each end of the DER management platform interface (with DER and utility systems), it is probable that numerous stakeholders, technology providers, and device/system configurations will be involved. While it may be tempting to lean toward proprietary interfaces in early stages of DER management, where a limited set of actors are involved, the future will require standardized interfaces to accommodate integration with a wide array of technolology providers and enable efficient coordination between additional actors.

The enterprise integration of utility DER management tools with other utility software applications is one of the most complex and expensive aspects of DER management and monitoring.[18] A phased integration is a pragmatic strategy for navigating the intricacies of DER management tools. The industry has been developing standards for DER management tools and functions for several years and will continue to make progress in the future. Where those standards are lacking, deploying DER management tools will likely require substantial time and resources to bridge the gap. Already, there are numerous vendors offering commercial solutions,[19] yet some utilities have preferred to develop tools in-house to meet their needs and budgets.

Finally, and likely most pertinent, is the question of if and when a utility should begin planning the deployment and integration of DER management tools. DER have been interconnected to the distribution for years, sometimes in large quantities, without the use of enterprise DER management tools, so why would they be needed in the future? The answer lies in the intended use of DER. Increasing hosting capacity through active management, improving operational flexibility, bolstering resilience, and enabling distribution and bulk system services are all use cases that are distinct from autonomous integration of DER.[20] These use cases typically involve some type of *active* management that cannot be achieved with one-off, semi-manual approaches. The emergence of these use cases is a strong indication that a formal, enterprise DER management solution is needed.

DER Market Liaison

As DER program offerings and wholesale market opportunities proliferate and become mature, a dedicated role within the control center is needed to provide an interface between grid operators and the dispatch of DER resources.[21] This is only practical when enterprise DER management tools become available. The DER market liaison or DER manager will evaluate pending requests for DER dispatch to ensure that distribution constraints are met, utilizing short term demand and production forecasts, as well as hosting capacity and distribution system state estimation results.

The DER market liaison may spawn from operational planners that monitor and verify DER impacts. But, once DERs are allowed to connect with flexible interconnections requiring the daily review and dispatching of generation within prescribed limits, the role will require a sophisticated understanding of the performance of DER under varying operating conditions and an understanding of hosting capacity and drivers that cause it to vary. Moreover, this role requires a detailed knowledge of distribution operating and planning constraints, a detailed knowledge of how DER impacts DMS control algorithms, and fluency in wholesale and distribution service coordination processes. The DER market liaison should be trained on DER management tools, familiar with the processes and procedures of the system operator, and aware of wholesale market interactions and activities.

17 *Understanding DERMS*. EPRI, Palo Alto, CA: 2018. 3002012049

18 *DER Management System (DERMS) Adoption Pathways*. EPRI, Palo Alto, CA: 2022. 3002025451

19 *Market Landscape of Commercial Utility DERMS: Utility DERMS Market Leaders Functionalities and Experience*. EPRI, Palo Alto, CA: 2021. 3002021860.

20 *Utility Strategies for Implementing Distributed Energy Resource Management Systems*. EPRI, Palo Alto, CA: 2024. 3002031038.

21 *Modernizing Distribution Control Center Operations: Evolving Operator Roles and Responsibilities.* EPRI, Palo Alto, CA: 2020. 3002019511.

CONCLUSION AND NEXT STEPS

There is no single pathway for utilities to progress through the proposed evolution of the distribution system. Multiple pathways may exist for a single utility depending on its specific environment. Changes in policies and regulations, rapid uptake of DERs, electrification trends, and decisions by customers to participate in wholesale and distribution markets are examples of factors driving utilities to achieve more advanced capabilities.

The designs and functional specifications for future distribution operations groups are wide ranging. In many jurisdictions, utilities are still working towards defining a strategic direction for greater integration of DER that provide services to the grid. To date there are many open questions about the roles and responsibilities of the operator of the future, as well as the systems, processes, and tools that will be needed to fulfill those roles. In all cases, to achieve the future vision utilities will need to deploy innovative solutions to enable coordination with bulk system operators, DER implementation, and integration with wholesale electricity markets, as well as identify and invest in new skillsets such as advanced forecasting, improved observability and controllability functionalities, data management and exchange, systems integration, and cybersecurity.

At the same time, tools and technologies are being deployed as part of grid modernization efforts. From centralized control to grid edge monitoring, there are many opportunities – seemingly at the cusp of adoption – that combined paint a picture of a distribution grid ready to enable limitless possibilities for loads and DER alike. However, for each tool in the toolbox, there are gaps fully unlocking the value of these investments. For example, DMS promise an optimized and orchestrated use of grid assets but are not able to be fully leveraged without accurate grid models and real-time monitoring, both of which still pose a challenge to many distribution utilities today. Therefore, effecting meaningful change towards the future vision of the distribution system requires multiple staged and timely improvements.

The capability roadmaps presented in this paper offer guidelines with which a utility can make transitional plans and monitor their progress. Because both DER adoption rates and public policy – the key drivers of the evolution of the distribution system – unfold at different rates and through unique pathways, each utility will need to assess the timelines for investments that align with their situation. While these timelines vary, the foundational investments needed to achieve core capability maturity goals are common across all utilities.

Utilities can leverage this roadmap, as well as the grid modernization roadmap process, to develop strategies that fit their environments, customer base, and goals. Fundamental activities in strategy development include performing a gap assessment against the capability roadmap and the capability milestones contained herein, followed by developing catered courses of action to advance current capabilities and reach future objectives. There is a growing wealth of knowledge and experience emerging in the industry stemming from utilities who have encountered rapid DER growth, progressive public policy, or both. Collaboration within the industry and among stakeholders is beneficial for all, as the sharing of experiences, successes, and challenges can help guide utilities along the right path.

DISCLAIMER OF WARRANTIES AND LIMITATION OF LIABILITIES

THIS DOCUMENT WAS PREPARED BY THE ORGANIZATION(S) NAMED BELOW AS AN ACCOUNT OF WORK SPONSORED OR COSPONSORED BY THE ELECTRIC POWER RESEARCH INSTITUTE, INC. (EPRI). NEITHER EPRI, ANY MEMBER OF EPRI, ANY COSPONSOR, THE ORGANIZATION(S) BELOW, NOR ANY PERSON ACTING ON BEHALF OF ANY OF THEM:

(A) MAKES ANY WARRANTY OR REPRESENTATION WHATSOEVER, EXPRESS OR IMPLIED, (I) WITH RESPECT TO THE USE OF ANY INFORMATION, APPARATUS, METHOD, PROCESS, OR SIMILAR ITEM DISCLOSED IN THIS DOCUMENT, INCLUDING MERCHANTABILITY AND FITNESS FOR A PARTICULAR PURPOSE, OR (II) THAT SUCH USE DOES NOT INFRINGE ON OR INTERFERE WITH PRIVATELY OWNED RIGHTS, INCLUDING ANY PARTY'S INTELLECTUAL PROPERTY, OR (III) THAT THIS DOCUMENT IS SUITABLE TO ANY PARTICULAR USER'S CIRCUMSTANCE; OR

(B) ASSUMES RESPONSIBILITY FOR ANY DAMAGES OR OTHER LIABILITY WHATSOEVER (INCLUDING ANY CONSEQUENTIAL DAMAGES, EVEN IF EPRI OR ANY EPRI REPRESENTATIVE HAS BEEN ADVISED OF THE POSSIBILITY OF SUCH DAMAGES) RESULTING FROM YOUR SELECTION OR USE OF THIS DOCUMENT OR ANY INFORMATION, APPARATUS, METHOD, PROCESS, OR SIMILAR ITEM DISCLOSED IN THIS DOCUMENT.

REFERENCE HEREIN TO ANY SPECIFIC COMMERCIAL PRODUCT, PROCESS, OR SERVICE BY ITS TRADE NAME, TRADEMARK, MANUFACTURER, OR OTHERWISE, DOES NOT NECESSARILY CONSTITUTE OR IMPLY ITS ENDORSEMENT, RECOMMENDATION, OR FAVORING BY EPRI.

EPRI PREPARED THIS REPORT.

About EPRI

Founded in 1972, EPRI is the world's preeminent independent, non-profit energy research and development organization, with offices around the world. EPRI's trusted experts collaborate with more than 450 companies in 45 countries, driving innovation to ensure the public has clean, safe, reliable, affordable, and equitable access to electricity across the globe. Together…shaping the future of energy.

EPRI CONTACT

NICK HEINE, *Team Lead, Sr*
865.218.8157, nheine@epri.com

ACKNOWLEDGMENTS

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

For more information, contact:

EPRI Customer Assistance Center
800.313.3774 • askepri@epri.com

3002031452 **January 2025**

EPRI

3420 Hillview Avenue, Palo Alto, California 94304-1338 USA • 650.855.2121 • www.epri.com

© 2025 Electric Power Research Institute (EPRI), Inc. All rights reserved. Electric Power Research Institute, EPRI, and TOGETHER…SHAPING THE FUTURE OF ENERGY are registered marks of the Electric Power Research Institute, Inc. in the U.S. and worldwide.