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Modern Distribution Grid

DSPx

Next-Generation Distribution System Platform

Strategy & Implementation Planning Guidebook

U.S. DEPARTMENT OF ENERGY | OFFICE OF ELECTRICITY

Acknowledgements

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Project Team

The DSPx Modern Distribution Grid series project lead is Joe Paladino, a Technical Advisor within the DOE-OE's Transmission Permitting and Technical Assistance Division, with project management support provided by Paul De Martini, Newport Consulting, and Jeffrey Taft, Pacific Northwest National Laboratory (PNNL).

This Guidebook was collectively developed by Paul De Martini, Jeffrey Taft, Joe Paladino, and the E3 team of Fritz Kahrl, Saamrat Kasina, and Ren Orans. Support was provided by Patricia D'Costa of ICF; Ken Fong and Andrew De Martini of Newport Consulting; and Beth Slaninka and Lindsay Kishter of Nexight Group.

Contributors

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Foreword

The Strategy and Implementation Planning Guidebook is intended to serve as a reference document for regulators at the state and community levels who are involved in directing or approving grid modernization plans prepared by utilities. The Guidebook is Volume IV within the Next-Generation Distribution System Platform Initiative (DSPx) Modern Distribution Grid series.

Given the complexity of technology decisions associated with advancing distribution system capabilities, the DSPx Modern Distribution Grid series has focused on developing a practical construct for moving through a grid modernization planning process in a holistic, yet methodical, manner. The planning guidance resulted from numerous discussions with both regulators and utilities, with the intention of formulating a consistent set of practices that can facilitate discussions and decisions between both stakeholders. The goal was never to provide a prescriptive approach, but rather to present a set of considerations that regulators could then apply to their specific circumstances; for example, their particular policy objectives, anticipated rates of distributed energy resource deployment, concerns regarding grid reliability and resilience, and the current state of their electric grid system.

The Guidebook presents **four key concepts** to consider within modern-day distribution system planning processes:

1. First, **well-articulated objectives** that convey scope and timing requirements are essential to guide the planning process. It becomes important in grid modernization plans to present a logic that links a proposed technology deployment roadmap back to stated objectives.
2. Second, grid modernization planning is one aspect of a **larger integrated distribution planning process**, in which foundational investments are required to enable advanced grid capabilities.
3. Third, undertaking a **system engineering approach** to determine functional and structural needs in line with stated objectives should inform technology choices. The Guidebook applies principles from grid architecture to govern objectives-based planning.
4. Fourth, technology implementation plans can adopt **proportional deployment strategies** (i.e., they can provide advanced grid capabilities where most needed first and/or initially improve grid function with simpler solutions, followed by more sophisticated approaches at a later time, as needed). The stratagem, termed “walk-jog-run,” is useful to consider when affordability constraints, modifications to utility processes, or technology readiness may dictate the pace of grid modernization.

Finally, it is important to note that the considerations provided in this Guidebook are based on current challenges, such as the need to modernize grid systems to accommodate myriad types of distributed energy resources. However, as new challenges arise, such as the emerging and persistent concerns to improve grid resilience (e.g., through cybersecurity and physical protection or reconfiguration schemes), we will need to continually evolve grid modernization planning approaches.

Table of Contents

1. Introduction

1.1 Chapter Summary

The Strategy and Implementation Planning Guidebook is intended to serve as a reference document for regulators at the state and community levels, as well as for planners involved in determining utility technology investments, who are involved in formulating or guiding the development of grid modernization strategies and implementation plans. The Guidebook is Volume IV within the Next-Generation Distribution System Platform Initiative (DSPx) Modern Distribution Grid series.

CHAPTER OUTLINE

- 1.2: Purpose of the Guidebook
- 1.3: How to Use the Guidebook
- 1.4: Key Guidebook Concepts

KEY POINTS

This chapter includes a discussion on:

- DSPx Volumes I, II, and III within the series and how they serve as reference materials to the Guidebook (Volume IV)
- The rationale for applying a grid architecture discipline to help address complexity
- The DSPx functional taxonomy and how it is used to determine grid capabilities in alignment with planning objectives
- The elements of a grid modernization strategy and supporting technology implementation plans

1.2 Purpose of the Guidebook

The electric grid continues to evolve due to the advent of new technologies, such as distributed energy resources (DER); the emergence of utility customers and third-party merchants in the active management and generation of electricity; and the need for structural approaches for protecting against dynamic physical and cyber threats. Evolving the methods and supporting tools and technologies used for grid planning and operations is crucial to ensure a manageable electric grid that is secure, reliable, resilient, and affordable. This Guidebook provides practical approaches that grid planners and decision-makers, particularly regulators, can use to modernize the electric grid.

Achieving coherent grid planning processes will require that state public utility commissioners and utilities have a shared understanding of the path forward, including how to balance short-term needs with long-term priorities. In addition, incorporating national-level concerns related to physical and cyber protection will expand the set of decision-makers in the planning process, including both federal organizations and local communities, to drive investments to improve resilience.

Since 2016, the U.S. Department of Energy (DOE) Office of Electricity (OE) has worked with state regulators, the utility industry, and other stakeholders through the DSPx initiative to develop the Modern Distribution Grid series.[1] The DSPx initiative was undertaken to develop consistent approaches in planning to inform investments in grid modernization. This series includes three prior volumes:

- **Volume I**, "Objective Driven Functionality," provides a taxonomy of functional requirements derived from state policy objectives and includes a discussion of grid architecture. The functional requirements are grouped into subsets belonging to grid planning, grid operations, and market operations, respectively.
- **Volume II**, "Advanced Technology Maturity Assessment," examines the maturity of various technologies needed to enable the functions presented in Volume I. The volume applies a technology adoption curve to show where various technologies reside along a maturation continuum. Understanding the relative maturity of a particular technology is an important practical consideration when developing realistic deployment schedules.
- **Volume III**, "Decision Guide," introduces a set of considerations for advancing grid structure and function based on various grid architecture principles. It also focuses on considerations for enabling integrated planning, situational awareness, operational communications networks, voltage management, operational coordination, and cybersecurity.

The Guidebook expands upon and refines information from the first three volumes based on lessons learned from the practical application of the framework by utilities, regulators, and other stakeholders across the country since 2017. The Guidebook presents the interrelationships between integrated distribution planning and grid modernization planning, discusses the development of grid modernization strategies and technology implementation plans, and introduces a cost-effectiveness framework that discerns valuation approaches depending on the type of investment being considered.

1.3 How to Use the Guidebook

The intended audience of the Guidebook are those developing and/or reviewing strategies and implementation plans for grid modernization. This is particularly important for articulating needed advancements in grid structure and function to effectively enable the integration and utilization of DERs[i] while ensuring that reliability, resiliency, safety, and operational efficiency needs are addressed.

The content of this Guidebook is the result of direct input from regulatory commissions and investor-, public-, and community-owned utilities across the country. The process-oriented, decision-making approach it conveys is generalized to enable its application to a wide range of jurisdictions and utilities across the United States. As such, the Guidebook intends to bridge understanding of the principles of

[i] The National Association of Regulatory Utility Commissioners (NARUC) defines a DER as "a resource sited close to customers that can provide all or some of their immediate electric and power needs and can also be used by the system to either reduce demand (such as energy efficiency) or provide supply to satisfy the energy, capacity, or ancillary service needs of the distribution grid. The resources, if providing electricity or thermal energy, are small in scale, connected to the distribution system, and close to load. Examples of different types of DER include solar photovoltaic (PV), wind, combined heat and power (CHP), energy storage, demand response (DR), electric vehicles (EVs), microgrids, and energy efficiency (EE)." See: NARUC, *Distributed Energy Resources Rate Design and Compensation*, 2016.

grid modernization planning across the regulator and utility decision-making domains while avoiding preferential treatment for certain utility business model and technology options.

This Guidebook is not focused on providing design-level solutions. Instead, it intends to provide holistic approach to developing grid modernization strategies that can then lead to specific technology deployment plans. It also seeks to provide regulators with advice on identifying necessary near-term grid modernization investments to meet more immediate needs, for example those associated with health, safety, or policy imperatives. The decision process it provides attempts to help regulators undertake near-term investment decisions that are aligned with long-term planning.

Grid modernization includes the application of myriad technologies including, but not limited to, technologies that enable digitalization (e.g., related to information management, communication, control, and automation), as well as the application of power electronics used in essential grid functions, such as reactive power management and switching operations. While this Guidebook does not focus on underlying physical infrastructure (e.g., poles and wires/cables, devices such as capacitor banks, transformers, electro-mechanical meters, and protection relays), it is important to recognize that any grid modernization effort is only as good as this underlying physical infrastructure.

As a final note, the Guidebook is a compendium of a large body of knowledge and practices that are employed in grid planning and modernization, such as systems engineering, technology management, and project management. Extensive references are made throughout to resources that may provide further explanation of key concepts or example approaches from policies, plans, and dockets. As a result, it is intended to serve as a useful reference to inform grid modernization discussions among regulators, utilities, and other stakeholders.

1.3.1 Organization

This Guidebook is organized into five chapters:

Chapter 1 — Introduction: Introduces the key concepts and organization of this Guidebook. It includes information on how to use the guide and its intended audience. Additionally, it explains the purpose of analyzing grid architecture and developing a planning process for grid modernization efforts.

Chapter 2 — Role of Grid Modernization in Integrated Distribution Planning: Describes the various processes associated with integrated distribution planning (IDP), providing the larger planning context that grid modernization planning takes place within. It provides an updated primer on IDP processes, including the assessments and engineering analyses that inform near- and long-term planning.

Chapter 3 — Modern Grid Strategy Development: Introduces a sequence of activities to develop a customer-oriented grid modernization strategic plan that traces needed functionality to defined customer, policy, and business objectives, creating an architecturally sound strategic roadmap.

Chapter 4 — Modern Grid Implementation Planning: Describes the logical sequence of activities to develop an implementation plan that is aligned to a grid modernization strategy and/or clearly identified objectives and functional requirements. Offers a systems-engineering approach for implementation planning.

Chapter 5 — Methodology to Evaluate the Cost-Effectiveness of Investments: Expands the discussion on the cost-effectiveness framework introduced in Volume III of the DSPx Modern Distribution Grid series. This chapter describes a targeted framework for economic evaluation, whereby utilities and regulators categorize investments, use appropriate methods to evaluate the various types of investments, and learn how to manage the risks associated with grid modernization investments.

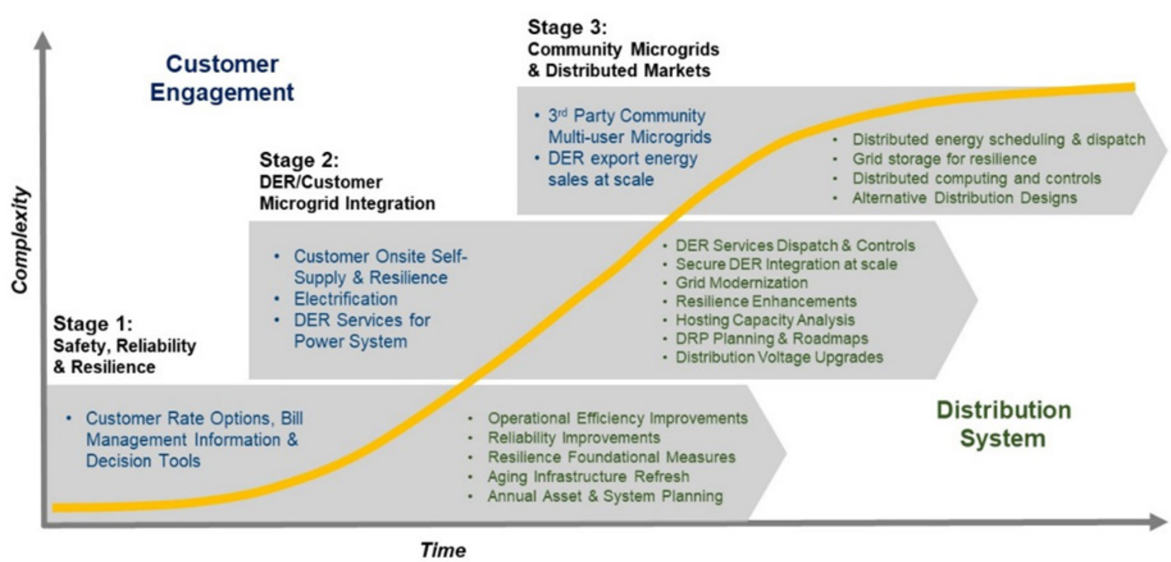
1.4 Key Guidebook Concepts

1.4.1 Addressing Grid Complexity through Grid Architecture

Modernizing the electric grid entails consideration of a wide range of existing and future needs in the context of rapidly evolving technology. The complexity of the electric distribution system is increasing as efforts are under way to integrate and utilize myriad DER, including microgrids, to improve reliability, resilience, and efficiency capabilities. This is not occurring consistently across the United States, but it is driven in part by various government policies and incentives.

Moving through the stages depicted in **Figure 1** requires improved operational capabilities to coordinate all entities owning or managing DER (e.g., the utility, customers, third-party merchants, and bulk-level system operators) and effectively manage power flow. For example, a distribution system at Stage 2 will need to address bi-directional power flow and implement capabilities to manage voltage and thermal loading often using new equipment and operational practices. Stage 3 may require the operation of distribution systems exhibiting a variety of grid configurations and ownership models. As a result, the distribution system planning process will need to ascertain the pace and scale of the evolutionary demands placed upon the electric grid and enable the formulation of appropriate modernization strategies.

Figure 1. Distribution Grid Evolution Complexity



To do so will require a systems view and a methodical, disciplinary approach to successfully address the scale and scope of dynamic resources envisioned in legislative and regulatory objectives for grid modernization. The DSPx initiative has applied the emerging discipline of grid architecture as a way to impart a holistic view of the grid and derive a process to help understand and define the many complex interactions that exist in present and future grids.

Grid architecture[ii] **is the synthesis of system engineering, network theory, and control theory as applied to the electric power grid.** The discipline of grid architecture allows grid planners and designers to examine the structure, behavior, and essential limits of an electrical system at any scale. At the highest level, the interrelated structures of concern include the physical electrical infrastructure; systems for sensing, communication, control, computing, and information management; the industry structure; market structure; and regulatory structure. Understanding how these structures interact provides insight into the formation of simplified design solutions.

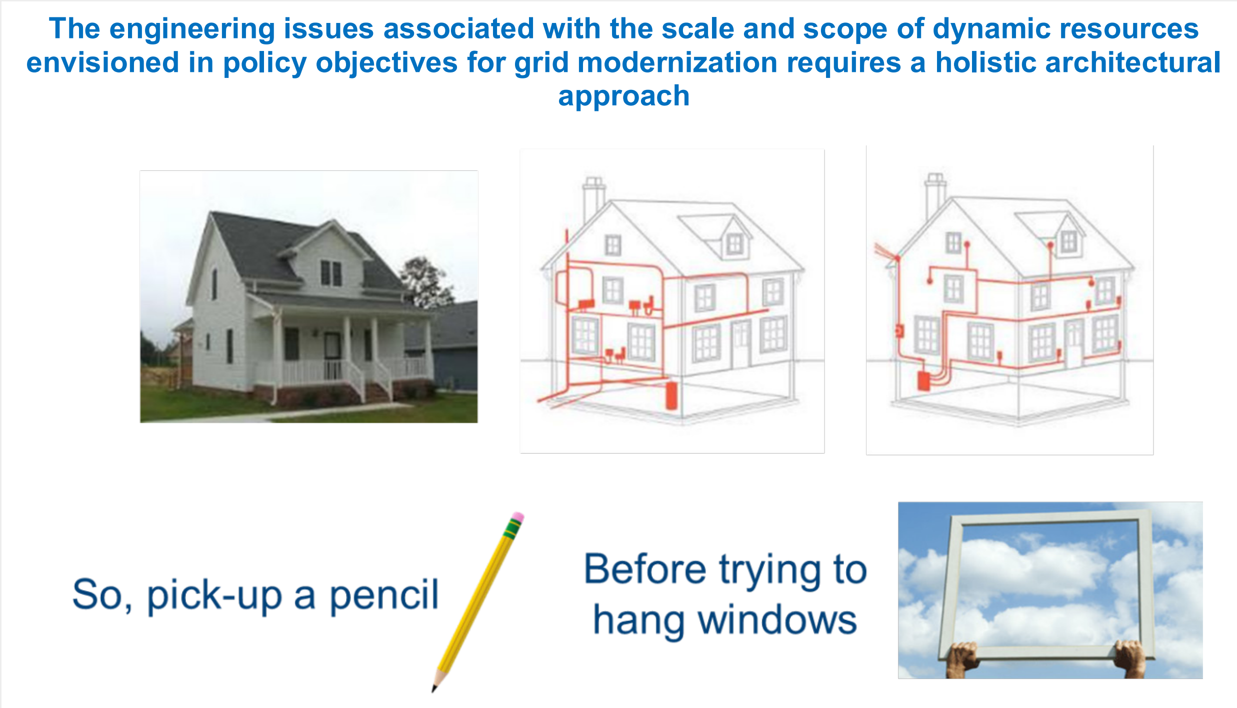
The practice of grid architecture is based on the view that once structural relationships are understood, more detailed system designs can be advanced that attempt to minimize unintended consequences.

The practice of grid architecture is based on the view that once structural relationships are understood, more detailed system designs can be advanced that attempt to minimize unintended consequences. This view also extends to the many elements that exist outside the utility but that interact with the grid, such as buildings, merchant DER, microgrids, and electric vehicles.

Much like how an architect designs buildings, the grid architect must understand both the objectives and constraints before beginning design work. This approach focuses on first defining customer needs, understanding policy objectives, and determining required functionality early in the development cycle; then documenting requirements; and then proceeding with design synthesis and system validation while considering the complete problem.

[ii] The discipline of grid architecture has been developed through work by the Pacific Northwest National Laboratory for DOE. More information on how it is applied is available at: https://gridarchitecture.pnnl.gov/.

Figure 2. Importance of Grid Architecture



As shown in **Figure 2**, it is essential to examine the entire structure before implementing solutions. Current grid modernization implementation practices today often begin with technology solutions (e.g., hanging the windows) without undertaking a more holistic structural analysis to determine how all the parts will interact in the near term and future. The DSPx initiative and this Guidebook employ such a systematic framework in the basic principles and methods of grid architecture.[2]

1.4.2 The DSPx Functional Taxonomy

This Guidebook provides a planning approach that supports users in developing holistic grid modernization strategies and subsequent, more detailed, technology implementation plans. Undertaking such an effort begins with an articulation of principles and policy mandates, as well as an understanding of the evolving needs of customers and associated trends. These factors inform the development of grid modernization objectives that consider timing with respect to addressing emerging trends, customer needs, and public policies. These objectives must be broken down into component parts and organized into a logical structure upon which grid modernization strategies and plans are shaped. This structure provides clarity for decision-makers and practitioners evaluating the complex issues to be sorted out at various stages of the grid modernization process, and it permits a process that can map technology decisions back to objectives.

Consistent with grid architecture principles and methods, the DSPx Taxonomy (as outlined in Volume I) is a four-level structure to logically organize and align the identified objectives, capabilities, and functionalities of a modern grid.[iii] The taxonomy framework is illustrated below in **Figure 3**, with further explanation of the levels provided after in **Table 1**.

As illustrated in **Figure 3**, the level of complexity grows as the level of information and details expand from a very small set of principles to ultimately thousands of business and technical requirements. Such a logical structure provides a line of sight from an objective to selection and deployment schedule of a technology.

Figure 3. DSPx Taxonomy Framework

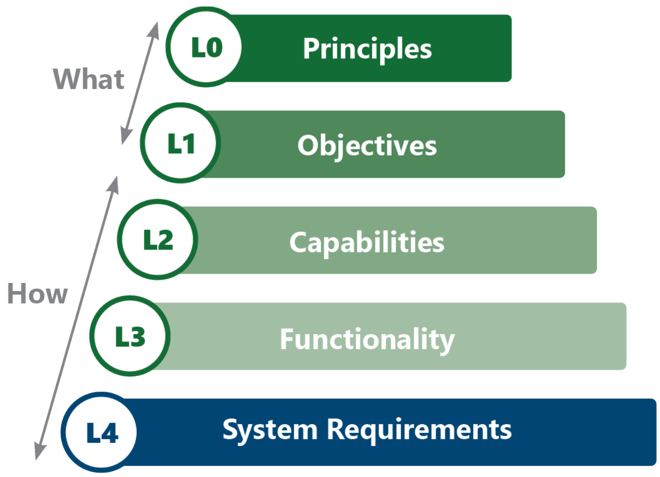


Table 1. DSPx Taxonomy Definitions and Examples

Taxonomy Level	Example
Level 0 – Principles: A principle is a fundamental proposition that serves as the foundation for a chain of reasoning. A jurisdiction's or utility's existing principles (or mission) provide the foundational context for grid modernization. These can be broadly applicable, but in some cases a set of principles are developed specifically for grid modernization.	*Example principle:* **Enable greater customer engagement, empowerment, and options for utilizing and providing energy services.**
Level 1 – Objectives: An objective is an envisioned or desired result or outcome. Broadly speaking, this level seeks to identify the key objectives of the distribution system based on a state's current legislative or regulatory efforts to modernize its electric grid and includes considerations for scale and timing. Insights drawn from this evaluation help inform the key objectives guiding the subsequent levels.	*Example objective (related to the principle above):* **Enable customer choice through information access for small businesses and residential customers to support energy management decision-making by 2022.**

[iii] This is a simplification of the original version and involved consolidating objectives and attributes, as well as functions and elements. Also, the categories of objectives, capabilities, and functionality have been refined to reduce duplication and improve use in practice. These refinements were based on feedback from industry and regulatory staff experience.

Taxonomy Level	Example
<u>Level 2 – Capabilities</u>: A capability is the ability to execute a specific course of action. Capabilities define specific actions required, which guide the identification of needed enhancements to existing business functions and/or new functions.	*Example capability (related to the objective above):* **Provide online customer access to relevant and timely information.**
<u>Level 3 – Functionality</u>: A functionality defines a business process or operational result of a process. Functionalities include processes and methods used to achieve or enhance existing capabilities and/or enable new capabilities needed to advance planning, grid operations, and market operations. Functionalities are often combined to enable a capability.	*Example function (related to the capability above):* **Enable remote meter data collection and verification.**
<u>Level 4 – System Requirements (Technology Implementation)</u>: System requirements combine hardware components and software systems to perform a set of functionalities. This level includes technology solutions that can meet specific business and technical requirements *(e.g., asset management tools, advanced inverters, data, and an analytics platform).*	*Example technology (related to the above function):* **Provide a customer portal.**

See Chapter 3 for examples of how utilities and commissions have developed and aligned principles, missions, capabilities, and functions within their grid modernization planning efforts.

This DSPx taxonomy is a decomposition and articulation of the policy and business functions that are identified, but not detailed, within earlier reference models, such as EPRI's Intelligrid[3] and the GridWise Architecture Council's (GWAC) Interoperability Context-Setting Framework.[4] As noted in these models, policy objectives and business goals serve as reference points for determining the functional requirements needed over time—leading to more detailed design considerations. An accompanying architectural analysis then provides an examination of key structural relationships before discrete technological solutions are chosen to ensure a coherent design and avoid unintended consequences.

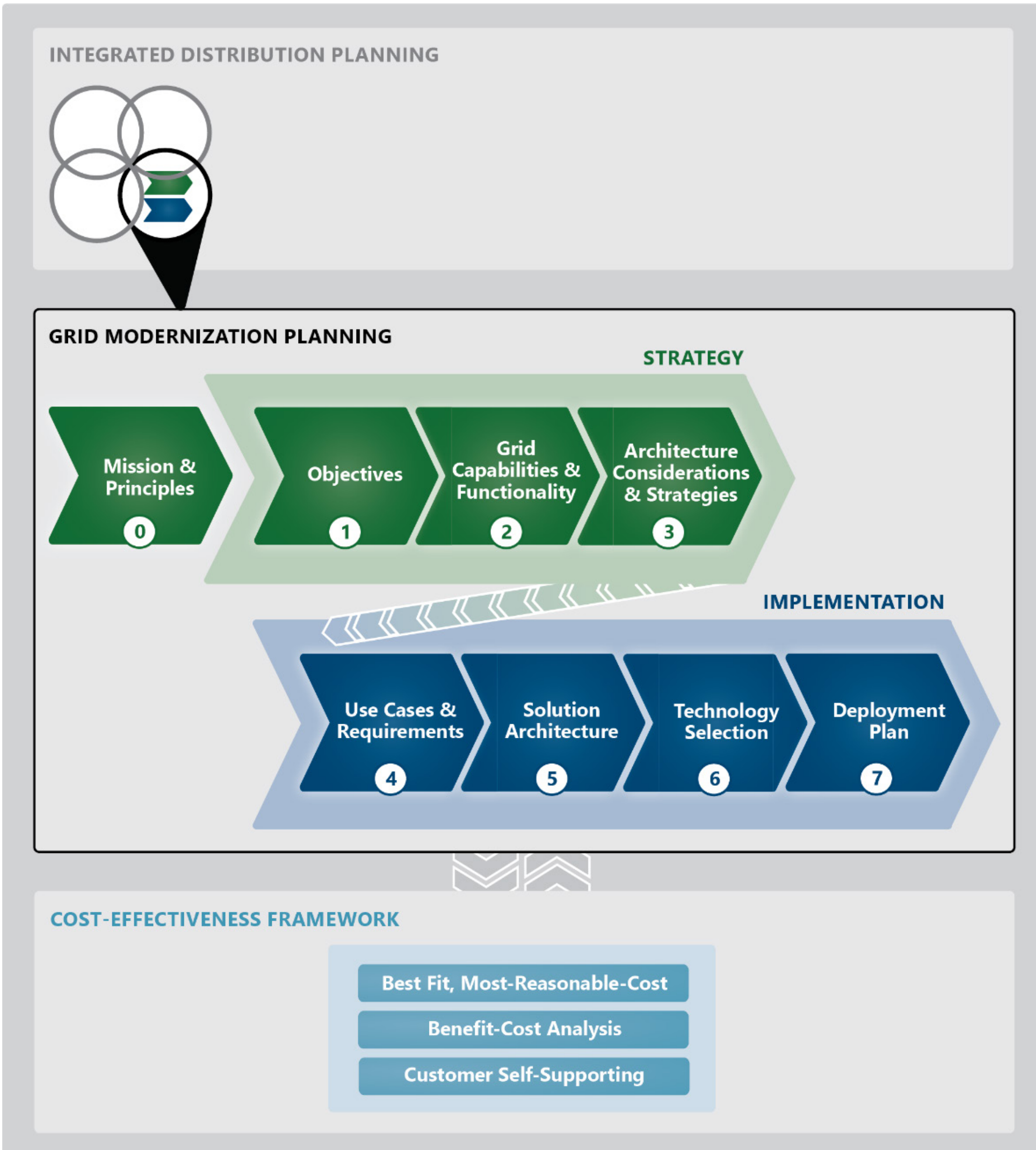
1.4.3 The Guidebook's Stepwise Planning Process

The application of the taxonomy and accompanying architectural[iv] analysis described above are embedded within the step-wise planning process presented here and detailed throughout this Guidebook.[v] Many states and utilities have already engaged in grid modernization efforts, developed strategies and plans, and begun implementing technologies. For those states and utilities already engaged in grid modernization efforts, this Guidebook can also provide a useful reference for updates to grid modernization strategies, integrating distribution planning, or for further grid modernization development.

[iv] This Guidebook may use the terms "architectural" and "structural" interchangeably.
[v] This Guidebook updates the seven-step, stage-gate decision process and considerations described in the Modern Grid Report, Volume III.

The stepwise planning process is illustrated in **Figure 4** and discussed in more detail throughout this document. This systemic perspective also recognizes that integrated distribution planning has an essential role in the development of both grid modernization strategy and implementation planning as discussed in Chapter 2.

Figure 4. Grid Modernization Strategy & Implementation Planning Process



Grid modernization strategy development, incorporating Steps 0, 1, 2, and 3 above, is discussed in detail in Chapter 3. A brief overview follows:

- Briefly, the first step of strategy development starts with identifying a set of **objectives** based on customer needs, government policies and associated mandates, utility business goals, and technology adoption trends. These objectives will help define the vision and scope of grid modernization for a particular jurisdiction and/or utility. Important timing considerations should also be identified.

- The second step begins with an assessment of current **grid capabilities and functionality** including the state of the physical infrastructure, as well as any smart grid and/or grid modernization investments and plans to-date. Determining the additional grid capabilities and functionality needed over time is informed by the objectives and augmented by near-term and longer-term needs identified in distribution planning (which is discussed more fully in Chapter 2). The resulting additional capabilities and functionality identified should be clearly traceable to the objectives.
- Step three involves development of holistic **grid architectural strategies** to achieve the identified needed capabilities and functionalities.

Implementation planning—incorporating Steps 4, 5, 6, and 7 above—ideally starts after strategy development which provides a logical foundation for more detailed design. These steps are discussed in greater detail in Chapter 4. A brief overview follows:

- In summary, implementation planning begins with the development of use cases for each of the functionalities identified within the context of the architectural strategies developed in Steps 2 and 3.
- Use cases are a method to identify detailed business and technical requirements that inform more detailed engineering designs. Use cases can also be employed to identify benefits, including the linkages to the strategic objectives.
- The documentation from the use cases combined with the strategies developed in Steps 2 and 3 provide the input needed for detailed solution architecture[vi] and system design development. The combination of the solution architecture and design efforts and use cases provide the reference information needed to assess technology solutions and undertake procurement and selection processes. Technology procurements by utilities may include sourcing for vendor equipment, systems, and services, such as operational software.
- The final step in implementation planning is the development of a deployment plan, or roadmap, that synthesizes the preceding strategy elements and implementation analyses into a logical sequence of deploying grid modernization investments. This roadmap provides the basis for developing cost estimates and linking the timing of benefits identified earlier that enable a cost-effectiveness assessment, as described in Chapter 5.

The numbered steps in Figure 4 above represent the ideal steps and sequence; however, in practice, regulators and utilities may not start at Step 1. Often, ongoing smart grid activity, begun over a decade ago, is evolving into grid modernization efforts to account for a wider set of objectives and capabilities needed. In these cases, some implementation of related grid modernization has and may be taking place. This may include, for example, advanced metering infrastructure (AMI) and distribution automation investments. This Guidebook acknowledges the need for a framework that is flexible and may be applied no matter the starting point for a more systemic approach to grid modernization.

[vi] Solution architecture is an architecture for a specific solution. An example of solution architecture is developing a design for a software system, such as a meter data management system, that would serve customer meter operations in support of customer service and outage management functions in support of grid operations.

2. Role of Grid Modernization in Integrated Distribution Planning

2.1 Chapter Summary

This chapter describes the various processes associated with integrated distribution planning (IDP),[5] providing the larger planning context that grid modernization planning takes place within. It describes the relationships between IDP, grid modernization strategy, and implementation planning and is intended to help inform discussions in the growing number of states[6] that are considering both integrated distribution planning and grid modernization. This chapter provides an updated primer on IDP and expands upon an earlier paper on IDP.[7]

CHAPTER OUTLINE

- 2.2: Grid Modernization Planning in the Context of IDP
- 2.3: Integrated Distribution Planning Inputs
- 2.4: Integrated Distribution Planning Analyses
- 2.5: Near-Term and Long-Term Distribution Planning
- 2.6: Performance Evaluation

KEY POINTS

This chapter includes a discussion on:

- Grid modernization planning as an outcome of IDP, not as a distinctly separate goal
- The importance of articulating clear objectives to guide an effective planning process
- The implementation of advanced grid functions being dependent on having a foundational grid capability regarding sustaining asset health and system reliability
- The components of an integrated distribution system planning process, including near-term and long-term considerations, and how they are related to the development of grid modernization strategies and subsequent technology implementation plans
- Key inputs into the planning process, e.g., considerations of load growth, DER adoption rates, and strategies to improve grid resilience based on risk assessments and the use of alternative grid configurations (e.g., through microgrids)

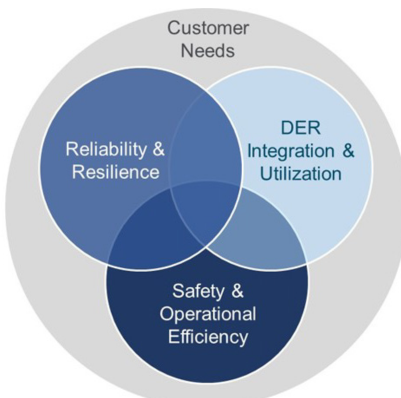
2.2 Grid Modernization Planning in the Context of IDP

Grid modernization strategy development and implementation planning—the focus points of this Guidebook—are based on the needs identified in a large integrated distribution planning (IDP) process that includes both a near-term and longer-term assessment. Experience across the United States has highlighted the need to proactively address changes to distribution planning, to optimize distribution operational and capital expenditures, and inform DER and microgrid development, as exemplified by the Puerto Rico Act:

> *"a resilient, reliable, and robust energy system with just and reasonable rates for all class of customers; make it feasible for energy system users to produce and participate in energy generation; facilitate the interconnection of distributed generation systems and microgrids."* [8]

IDP provides a systematic approach to satisfy customer service expectations and the specific grid planning and design objectives related to reliability and resilience, safety and operational efficiency, and DER and microgrid integration and utilization (see **Figure 5**). These three focus areas of modern distribution planning require a unified process integrated with system forecasts and corresponding resource and transmission planning.

Figure 5. Distribution Resource Planning Focus Areas



2.2.1 Integration of Grid Modernization with Distribution Planning

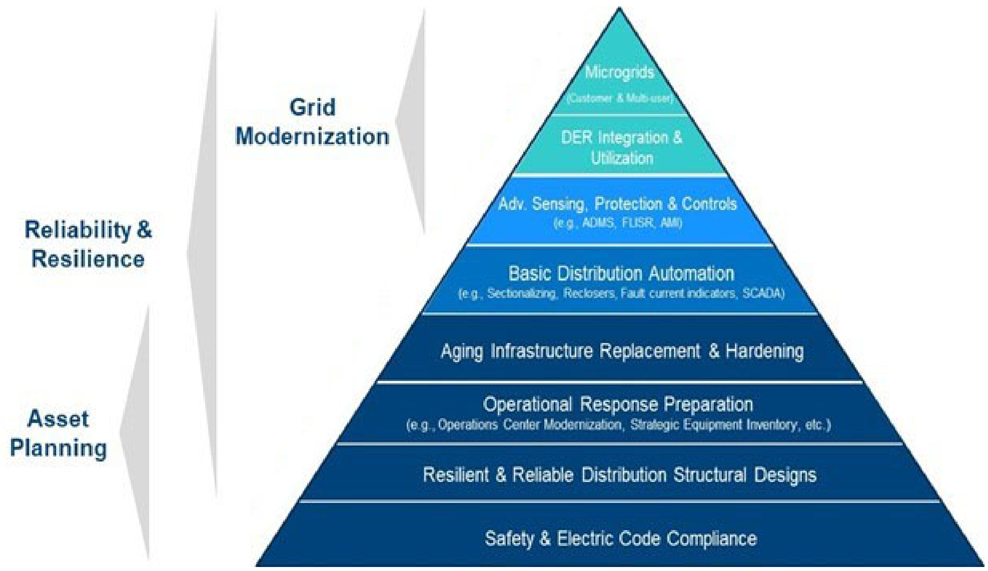
Modern distribution systems are built upon foundational capital and operational investments. Grid modernization investments cannot be planned in a vacuum—they must be aligned with traditional asset planning and integrated with other planning objectives for resilience and reliability. The following planning analyses are considered together in both near-term and long-term integrated distribution system plans:

- **Asset planning:** This involves assessing the current state of a distribution system infrastructure in terms of condition and operational performance and focuses on proactively addressing safety, code compliance, and basic reliability issues.
- **Resilience and reliability planning:** These have evolved from a primary focus on hardening of infrastructure to considering additional solutions, such as microgrids, alternative circuit designs, and advanced technologies, that would increase the ability to withstand specific threats and improve system reliability.

- **Grid modernization:** This effort is an evolution of the smart grid efforts that began more than 15 years ago. Grid modernization has an expanded horizon in many jurisdictions to include larger scale integration and use of DER and microgrids to meet both customer and power system needs.

As depicted in **Figure 6** below, each of these activities have overlapping implications for the distribution infrastructure and operational dimensions that should be integrated to address a state's objectives. This pyramid also illustrates prioritized investments for building a resilient, modern distribution system. The foundational activities shown at the bottom of the pyramid must be addressed before implementing the more advanced grid modernization activities shown at the top of the pyramid.

Figure 6. Distribution Infrastructure Investment Prioritization Pyramid



Additionally, it is highly desirable for capital plans to both optimize construction activities and minimize potential re-work. A distribution resource planning process will help align the three discrete planning analyses outlined above to ensure that asset and technology deployment will be most efficient.

Such an integrated planning process, as described in an example from the Minnesota Public Utilities Commission,[9] is necessary to achieve "comprehensive, coordinated, transparent, integrated distribution plans" to:

- "Maintain and enhance the safety, security, reliability, and resilience of the electricity grid, at fair and reasonable costs, consistent with the state's energy policies.
- Enable greater customer engagement, empowerment, and options for energy services.
- Move toward the creation of efficient, cost-effective, accessible grid platforms for new products and services, with opportunities for adoption of new distributed technologies.
- Ensure optimized use of electricity grid assets and resources to minimize total system costs."

The Commission also notes that this planning process will provide information that it can use to understand near-term and longer-term distribution system plans, cost-benefit analyses for particular investments, and analyses of impacts to ratepayer cost and value.

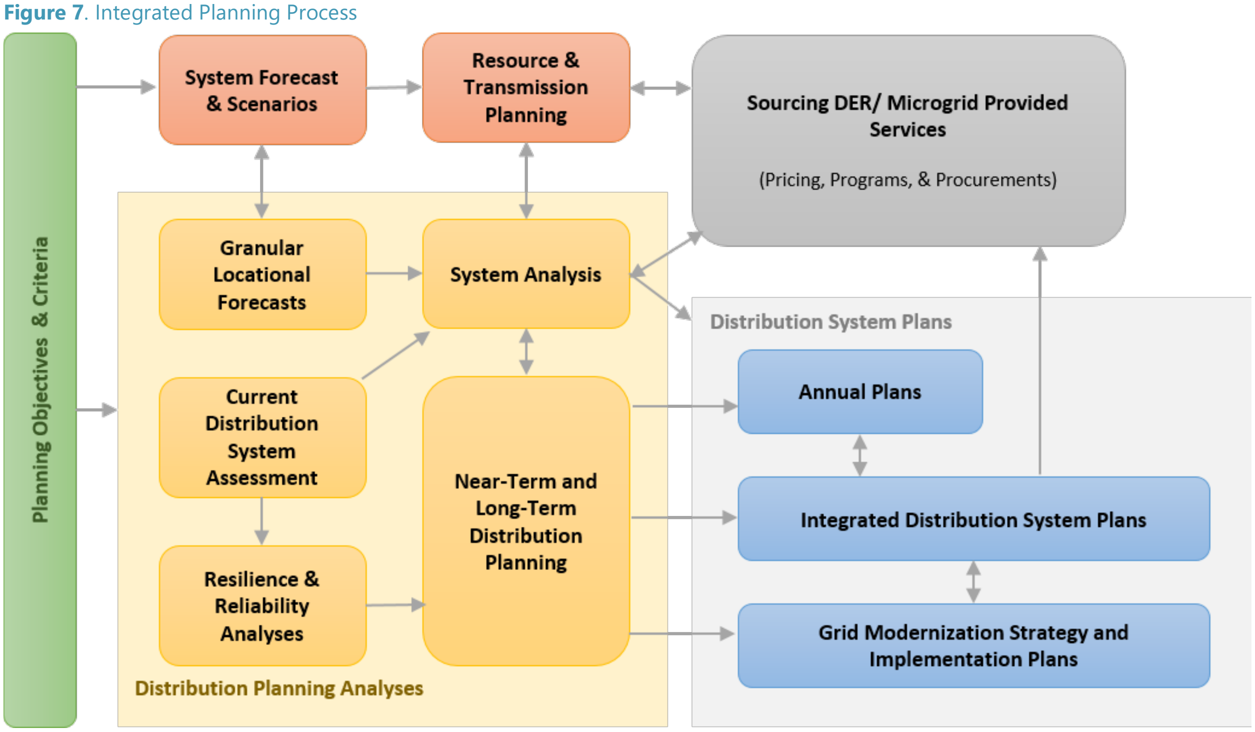
2.2.2 View of an Integrated Planning Process

At the highest level, the IDP process includes these basic elements:

- Identifying near-term and longer-term objectives and planning criteria (including minimum performance requirements), which together drive the IDP process
- Performing best practice engineering analysis
- Determining incremental grid needs, system changes, or changes to existing plans
- Identifying and evaluating potential solutions (e.g., grid capital, operations and maintenance, private solutions) using risk-based engineering-economic methods

A more detailed view of an integrated planning process is provided in **Figure 7.** Integrated Planning Process**,** which shows the various elements and their relationships. The figure depicts how an IDP relates to resource and transmission planning. This chapter describes these process elements and interrelationships in more detail in the context of both industry best practice and a state's objectives. Note that the process begins with a set of well-defined planning objectives and criteria which typically consider policy goals, changing customer expectations, and foundational requirements, for example, those related to security, resilience, and reliability improvements.

Figure 7. Integrated Planning Process



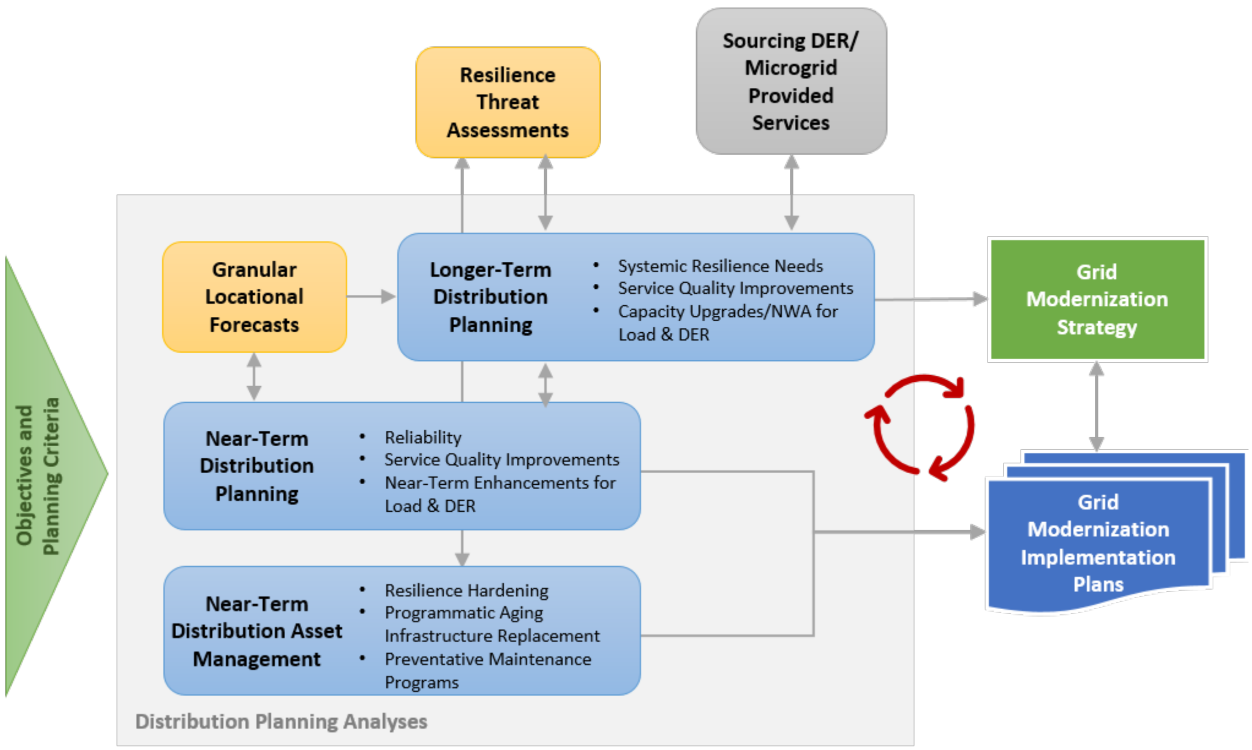
2.2.3 Grid Modernization Planning – One Aspect of IDP

Modernizing the grid is an outcome of distribution planning, not a distinctly separate goal. It is something that is integral and informed by all planning processes, including asset planning, near-term, and long-term planning. The implication is that, in the future, exploring and assessing the value new technologies and capabilities could bring to the system will be integral to the way in which utilities plan, not a separate objective to modernize to grid.

To understand the relationship between IDP and grid modernization planning, it is helpful to focus on the three distribution planning processes typically conducted that may identify needs that inform the development of grid modernization strategies and implementation plans, as depicted in **Figure 8. :**

- Near-Term Distribution Planning
- Distribution Asset Management
- Longer-Term Distribution Planning

Figure 8. Relationship of Grid Modernization Planning to Integrated Distribution Planning

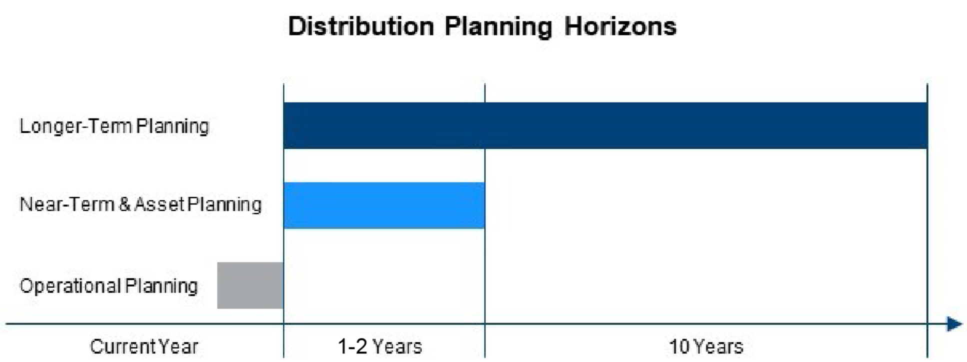


Long-term planning typically informs grid modernization strategy development and subsequent refinements, whereas near-term, annual planning informs implementation planning details. These cyclical interactions are important opportunities to accommodate course corrections given the uncertainties that will impact the distribution grid over time.

There are three fundamental time horizons that may be employed for distribution planning processes (as shown **Figure 9**):[vii]

- *Operational planning* to address immediate concerns (intraday through the current year)
- *Near-term distribution planning and asset management*, which may be conducted annually with time horizons of one to two years
- *Longer-term distribution planning*, which may be performed on a 2–3-year cycle with time horizons of 5–10 years

Figure 9. Example Distribution Planning Horizons

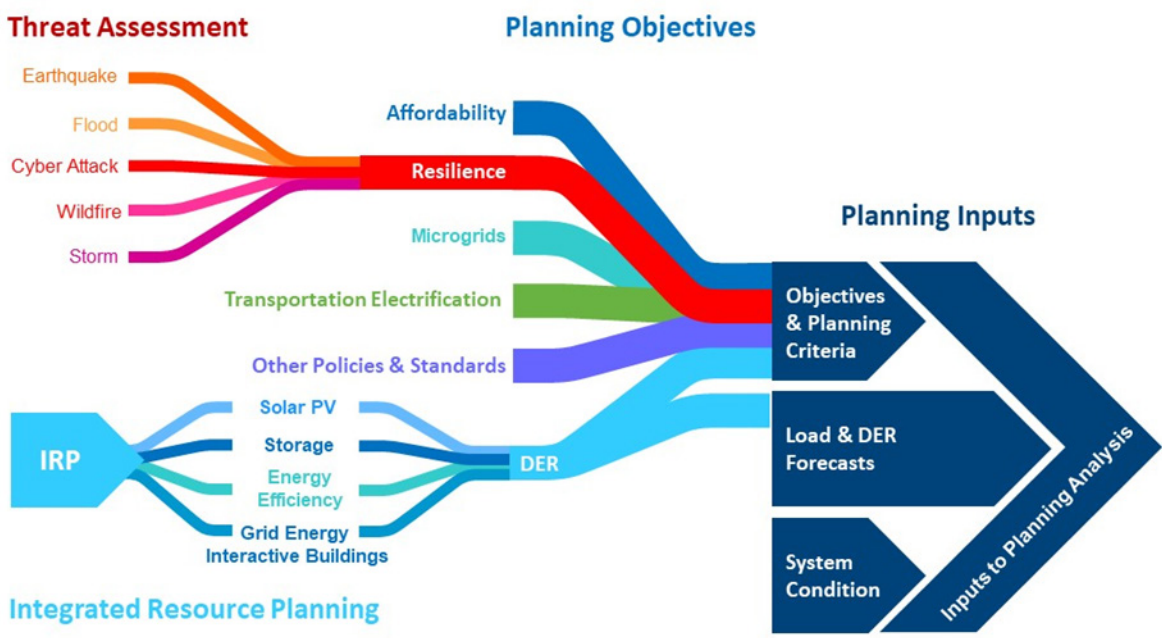


[vii] Note that distribution planning horizons and cycles vary across the country based on specific needs of those service areas.

2.3 Integrated Distribution Planning Inputs

As a starting point, the IDP process includes a number of interrelated activities that are driven by planning objectives based on customer needs, policies and standards, DER and microgrid integration and use forecasts, and current state of the distribution system (i.e., the starting point for planning). **Objectives** and **planning criteria**, specifically, are informed by public policy, electric service quality standards and safety criteria, resilience threat assessments, and integrated resource planning results related to distributed resources, as illustrated in **Figure 10**. These planning objectives and criteria provide key inputs for the engineering planning analysis that follows.

Figure 10. Distribution Resource Planning Inputs

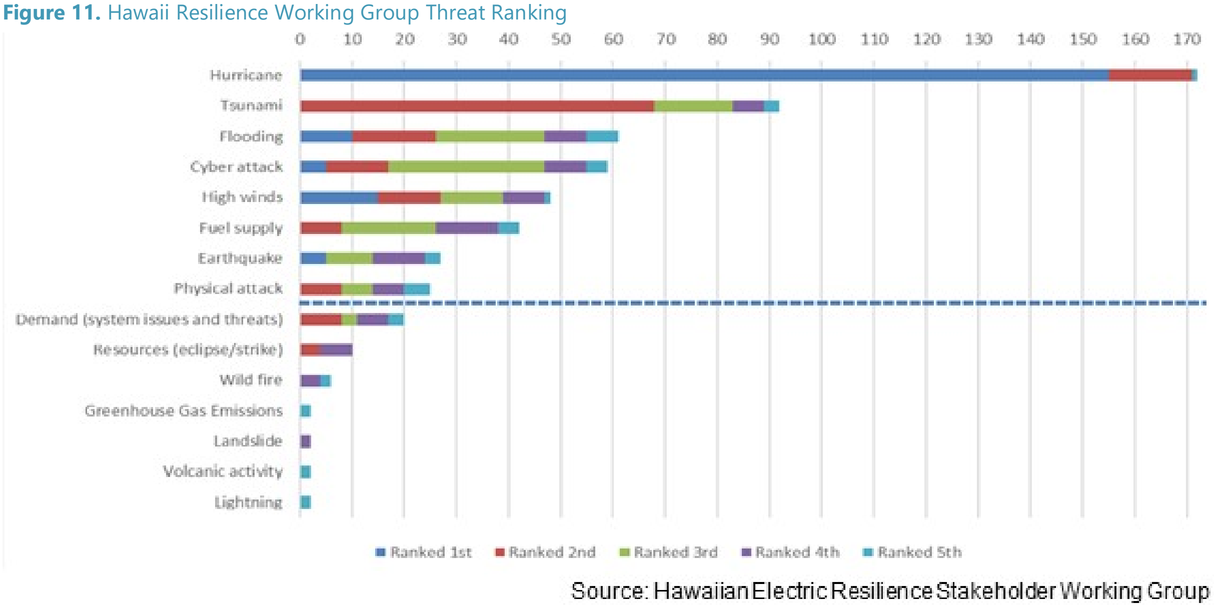


2.3.1 Threat Assessment

The federal government, states, and utilities have recognized the need to enhance the resilience of the nation's distribution grid to reduce the impact from major events such as natural disasters and cybersecurity events on our quality of life, economic activity, and national security. Disruptive events of various potential scopes should inform structural considerations and functional requirements to improve the resilience of the distribution system. This poses a significant challenge for planning as each threat type often has distinct potential threat impacts on a distribution system. For example, a severe winter storm may cause potential ice loading damage to overhead lines in one area, whereas a spring flood or storm surge may cause damage to underground facilities in another area.

Therefore, an important step is to perform a threat assessment with key federal, state, and local stakeholders, as appropriate, to identify the potential threats and assess the risk of their probable impacts. As discussed in detail in NREL's Resilience Planning Guidebook, this involves a structured assessment of the threats together with their impacts and likelihoods, as well as the associated power sector vulnerabilities and their severities.[10] A threat assessment process is being employed in Hawaii;[11] one work product is illustrated below in **Figure 11**.

Figure 11. Hawaii Resilience Working Group Threat Ranking



The scale, scope, and duration of disruptions also shape the economic impact and related value of solutions. It is essential to unpack distribution resilience threats to gain the insights necessary for planning and solution development. From this threat assessment, a set of planning considerations and criteria may be developed. However, there is no single set of distribution resilience planning criteria for any single utility given the range of threats and potential severity of impacts. These considerations and criteria inform the planning analysis processes involving resilience analysis to start.

2.3.2 Integrated Resource Plans

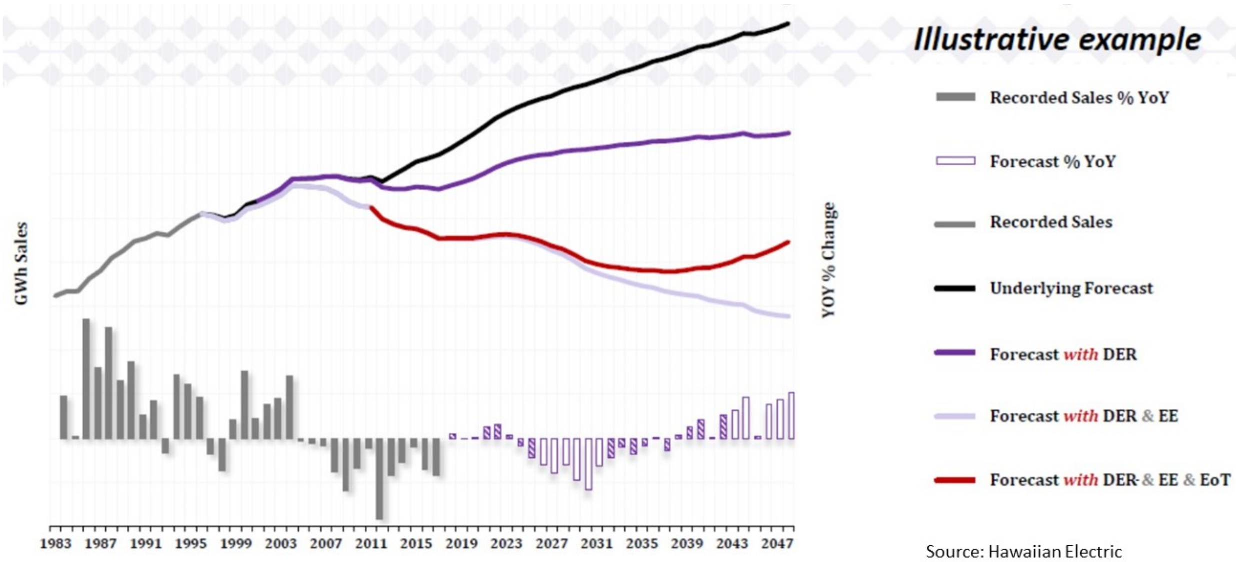
Integrated resource plans (IRPs) are used to identify the incremental generation and demand-side management resources required to meet changes in energy demand and resource availability over a long duration, often 10–20 years. Long-term, system-level, net-load forecasts are a key input to an IRP as discussed below. These forecasts include customer adoption of DER to create a baseline for determining incremental resource needs. An IRP also addresses contributing factors that impact electricity supply and delivery, including renewable portfolio standards, resilience and reliability objectives, and DER (including energy efficiency) policies at both federal and state levels.

Resource plans increasingly include identification of additional distributed generation, storage, and demand management and energy efficiency programs needed to contribute to overall resource needs for energy, capacity, and ancillary services. These planned incremental distributed resources are combined with consumer DER adoption forecasts to inform distribution planning.

2.3.3 System-Level Load and DER Forecasts

System-level DER and load forecasts are primary inputs to both resource planning and distribution planning. These forecasts reflect macroeconomic trends, policy changes, retail rates, technology advancements, and diffusion patterns. The load forecasts are developed using long-term forecasts of aggregate consumer energy consumption (demand and load profiles) for a specific area (e.g., state, utility service area). This base load forecast is adjusted to reflect the net effects of customer adoption of distributed generation, storage, electric vehicles, and other load-modifying devices. Each DER component is layered onto the load forecast to reflect the net effect, as shown in **Figure 12**.

Figure 12. Long-term DER & Load Forecast Layers



Note that customer DER is treated as an offset to customer load (net load), but if a jurisdiction has retail tariffs that allow export energy from distributed generation and storage to support resource adequacy, then these DER will need to be considered in the resource mix and not net load. The resulting aggregate net load forecast is used in an IRP analysis.

System load and resource forecasts, inclusive of DER, reflect broad changes across a jurisdictional area and are not detailed to a specific location at the distribution system in an IRP. Distribution planning requires a more granular forecast that is derived from this system level forecast along with the incremental DER identified in an IRP.

2.3.4 Distribution Planning Criteria

Planning criteria are system design and operating parameters established to ensure safe and reliable grid operation under normal, transient, and contingency conditions, and they must be considered in planning processes. Such criteria often define requirements for the management of current thermal limits, voltage, and frequency, as well as service quality to customers.[viii] They are often expressed in national, state, and regulatory standards for service quality and reliability that are also codified in regulation. Regulatory standards also cover many other areas including clean energy, interconnection of distributed energy, resilience, and customer service.

[viii] An example of a high-level planning criterion that would then guide more detailed engineering requirements may be articulated as follows: “neither end-use customer load nor interconnected customer generation shall cause any power quality-related issues to the utility grid or any utility end-use customer.”

These standards define acceptable and unacceptable levels of distribution system performance, utility reporting requirements, and applicable incentives and/or penalties for utility performance.[ix] They also establish the minimum performance requirements that any additional requirements, such as DER and microgrid integration and utilization, must not negatively impact.

Planning criteria will also be informed by resilience and reliability objectives. These objectives should be translated into engineering and operating criteria. For example, an objective to reduce customer outage exposure may involve designing the system to enable an adjacent circuit to pick up the load of a portion of another circuit. This N-1 contingency operating criteria will be translated into a limit on the normal loading of circuits to allow the emergency transfer of an adjacent circuit segment.

2.3.5 Distribution System Condition

Any planning effort must begin with a clearly established starting point. In distribution planning, this starting point is to identify the existing **system condition** and **operational performance** since the last plan. System condition refers to the "health" of individual infrastructure components (e.g. service transformer, pole, substation breaker), whereas operational performance refers to the performance of both individual pieces of equipment and apparatuses as well as the collective system. Determining system condition requires effective data on distribution infrastructure including relative age, current condition, and stress conditions experienced (e.g., faults and overloads), among other sources. Determining operational performance requires data on the performance metrics of equipment, feeders, and systems related to maintaining customer service quality and meeting reliability and resilience criteria.

2.4 Integrated Distribution Planning Analyses

2.4.1 Granular Locational Forecasts

Distribution planning requires a closer examination of the potential changes to load and DERs at the level of a substation, feeder, and in some cases sections of a feeder. This involves developing a granular **locational forecast** as well as more detailed **temporal forecasts**. These locational forecasts incorporate information regarding specific new housing and commercial developments based on existing or anticipated customer service requests, DER adoption and use patterns, and other relevant information that will shape the forecast.

System forecasts of DER adoption and use inform the development of more "bottom-up" granular locational forecasts that are applicable to the specific distribution planning areas under assessment. The aggregate results are typically compared with system level projections; ideally, the granular distribution forecasts in aggregate comport with the system level forecasts.

Distribution locational forecasting also involves assessing available load data. For example, the development of circuit-level load forecasts draws upon substation transformer (and circuit) loading data sourced from a SCADA system, historical circuit data (e.g., from load studies), and customer meter readings (i.e., AMI or other metering as available). Assessing this load data intends to identify the

[ix] An example of such a standard may be found in: Michigan Department of Public Labor and Economic Growth, Public Service Commission, *Service Quality and Reliability Standards for Electric Distribution Systems*, https://www.michigan.gov/documents/mpsc/Service_Quality_Standards_672262_7.pdf.

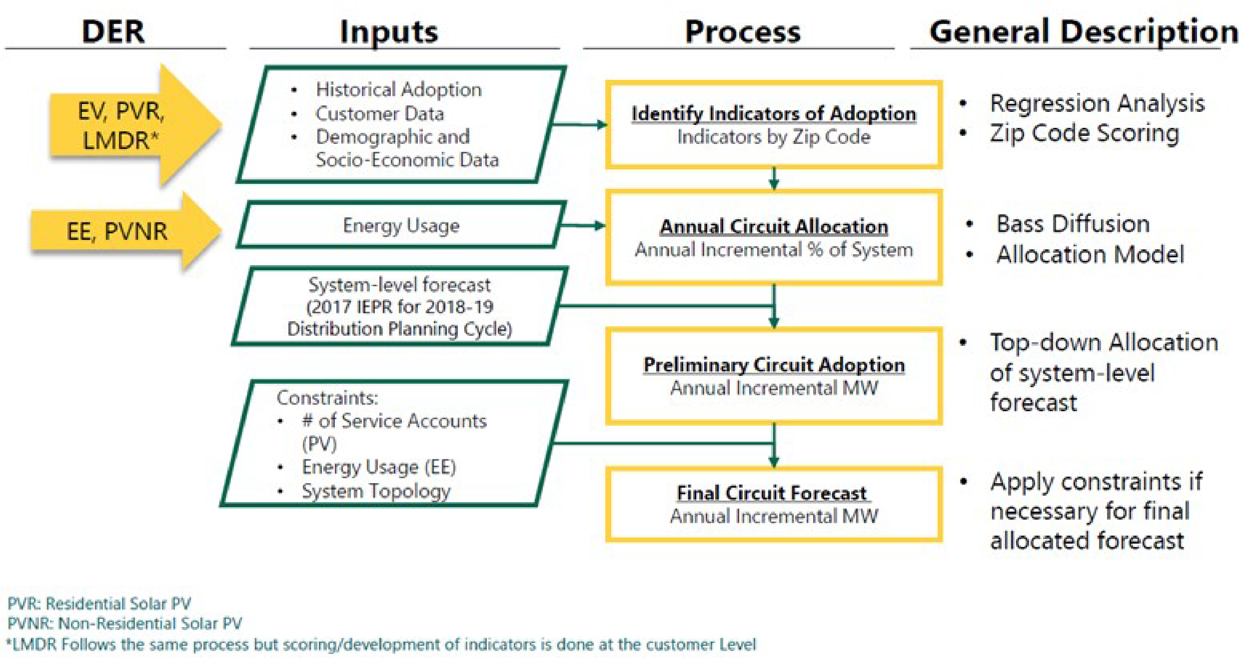
temporal loading profile and related demand observed at the substation transformer and circuits that the grid must accommodate.

Along with historical loading information, other inputs that contribute to long-term distribution forecasts include: projected customer service requests (i.e., from new housing developments), information from marketing or the media related to potential commercial development, and historical load growth rates, which are geographically dependent. Predictions for increases in electricity demand due to the anticipated rise in use of electric devices, such as electric vehicles and heat pumps, may also become a significant input in certain areas.

These load forecasts, which are modified by DER adoption estimates and developed at the circuit level, are needed to assess the net-load effects as well as intended and unintended export energy quantity and timing. As such, "loading" is increasingly bi-directional in nature, with several utilities already experiencing the highest demand on some circuits driven by reverse power flow from DER. In high-DER environments, the daytime minimum load may be the period of the greatest risk of operation being outside of thermal or service quality standards. Higher fidelity temporal forecasts are dependent on the availability of data and models to prepare these forecasts.

An example of the development of locational DER forecasts is illustrated in **Figure 13** below from Southern California Edison. This figure is from a presentation on the adaptation of system-level DER forecasts and related uncertainty considerations held in the California Distribution Forecasting Working Group.[12] These granular locational forecasts in turn inform both near-term and longer-term distribution planning.

Figure 13. SCE's Overall DER Disaggregation Process



Note that distribution-level forecasts, particularly forecasts beyond five years, are inherently more uncertain than system-level forecasts given the lengthened planning time horizon. For example, policy changes, a single large DER interconnection, new residential or commercial development, electric vehicle fast-charging infrastructure, or a commercial business closing can substantially change a circuit's loading shape and magnitude quickly. Conversely, a system-level forecast inherently benefits from the law of large numbers and resource and load diversity that have a damping effect on potential variability of projected aggregate loading and related bulk power system needs.

2.4.2 Current Distribution System Condition Assessment

The assessment of the current asset condition and operational performance of a system is essential to determine compliance with planning criteria and service standards and to fulfill obligations to provide safe, reliable service to customers at a reasonable cost. This assessment includes determining the current condition of grid assets, asset loading and utilization, and feeder and substation reliability in relation to standards and operational performance metrics. In addition, monitoring, tracking, and assessing the performance of distribution equipment allows utilities to plan and implement timely corrective actions to achieve desired resilience and reliability objectives and standards.

2.4.2.1 Asset Condition

Three key elements provide the foundation for assessing the current distribution system condition: 1) Asset Information, 2) Equipment Design Standards, and 3) Asset Management Protocols.

Asset Information

Determining asset condition requires effective data on distribution infrastructure, including relative age, current condition, and stress conditions experienced (e.g., faults and overloads), among other aspects. Asset information may take several forms and incorporate varying levels of sophistication. At a minimum, the fundamental information needed should be related to each component of the electric system, including equipment models, manufacturers, and equipment age. Beyond this, information is collected on the service history of the equipment, including design ratings, historical loadings, results of inspections and diagnostic tests, and other items. Utilities with the best reliability performance have implemented asset-health and condition databases that incorporate intelligent algorithms and logic to identify, rank, and track the condition of distribution system assets.

Equipment Design Standards

Utilities maintain compendiums of equipment and construction design standards that determine the fundamental building blocks of the electric system. Standards specify characteristics of every element of the system, with some examples including:

- Conductor standards – These specify the minimum standards for the various types of distribution lines. For example, a conductor of a certain heavy-duty rating may be specified for the main run of a circuit versus a lateral circuit that does not carry as much electricity.
- Pole standards – These specify the characteristics of poles used to carry overhead conductors—for instance, specifying the use of wood, concrete, steel, or fiberglass poles for differing field conditions.
- Equipment foundation standards – These specify the material, design, and installation for the foundations of electric infrastructure, such as breakers, transformers, relay cabinets, substation bus, and others. These standards might specify different height of installation to withstand flooding and storm surge potential.

Asset Management Protocols

Utilities have specific processes and approaches for the operation and maintenance of electric infrastructure assets, which include regulatory requirements regarding protocols such as:

- How long equipment may be used for
- Whether equipment is allowed to run to failure
- How equipment is monitored and replaced at a certain level of condition or replaced when obsolete
- Inspection programs, routines, and cycles

Furthermore, many utilities have adopted formal standards and certifications for the optimization of their physical asset. One such standard is International Organization for Standardization (ISO) 55001:2014, Asset management—Management systems—Requirements.[13]

An assessment of the current system condition and performance establishes a baseline for annual and longer-term planning. The appropriate management of assets and use of processes to ensure system reliability are prerequisites to the effective employment of grid modernization technologies, techniques, and practices.

2.4.2.2 Operational Performance

Operational performance assesses the performance of the distribution system since the previous distribution plan (typically, the previous year's annual plan). It helps identify the performance required of equipment and control systems to maintain customer nominal voltage as well as customer exposure to outages. This performance information provides the basis for identifying the frequency, duration, and nature of outages as reported in the IEEE 1366 standard[14] on reliability metrics—the System Average Interruption Duration Index (SAIDI), Customer Average Interruption Duration Index (CAIDI), and Momentary Average Interruption Frequency Index (MAIFI). These reliability metrics are typically reported by utilities annually and used to benchmark performance against peer utilities with similar distribution system characteristics. Benchmarking results are used to inform capital investment prioritization (e.g., focusing efforts on improving the worst-performing feeders).

To assess the performance and health of utility assets, a utility must perform the analyses discussed in the following sections to propose maintenance and/or capital programs. This requires distribution system and asset performance data to effectively evaluate performance, such as tracking information on the service history of the equipment, maintenance and inspection cycle data, information on historical loadings, results of inspections and diagnostic tests, and equipment performance data. Such planning typically requires robust analytics and engineering tools to effectively evaluate the current system and future scenarios regarding performance. Most large utilities—i.e., those with more than one million customers—have expanded their SCADA systems to include monitoring of distribution substations, including feeder breakers.

Evaluating increasing numbers of grid-edge devices (e.g., DER) depends upon having quality, available data, which determines the efficacy of the models used to produce these evaluations that then inform a utility's investment plans. For example, hosting capacity analysis requires asset data, peak-load data at various points on the distribution system, and data on the normal and emergency ratings of assets. Thus, it is essential to ensure the data are available and of appropriate quality to perform the various analyses desired.

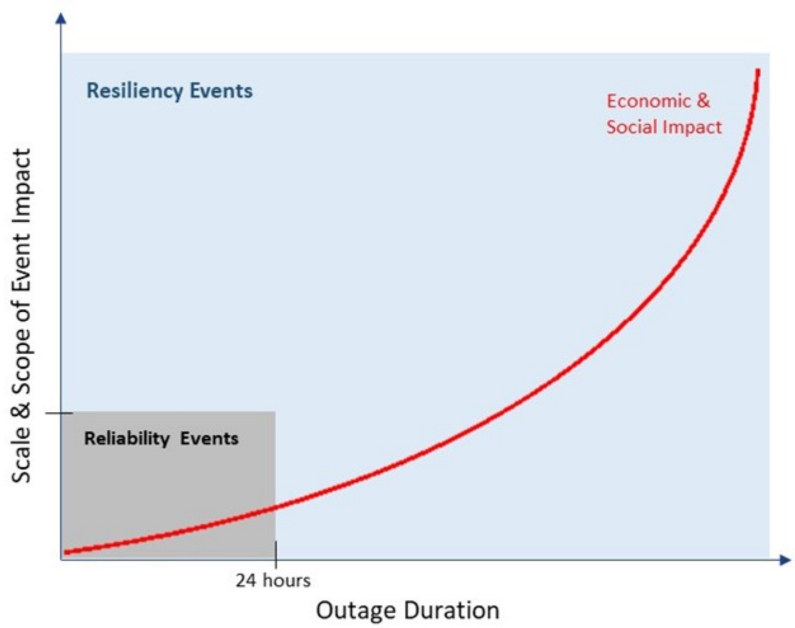
2.4.3 Resilience and Reliability Analyses

Adversarial threats pose an increasing level of risk to distributed power networks. Continuing the integrated planning process outlined previously in **Figure 7**, this section focuses on conducting an analysis of distribution system capability to withstand potential threats (large and small) and recover quickly. Resilience and reliability planning cover a spectrum of event types as outlined below:

- **Resilience events** cause larger geographic impact on distribution and/or bulk power system with long-duration outage—typically greater than 24 hours and classified as "Major Events" according to IEEE 1366.
- **Distribution-level resilience events** occur when there are similar infrastructure failures as ones that happen in reliability events (e.g., wires down, poles broken, transformer failure, fuses blown) but at a greater scale that requires significant complexity to address.
- **Reliability events** have a local impact with short duration outage—generally less than 24 hours and not classified as "Major Events" according to IEEE 1366.

The fundamental difference between resilience and reliability events is illustrated in **Figure 14.** Reliability-Resilience Event Continuum. The various domains presented in the figure dictate the scale and scope of coordinated response planning; large-impact events will require planning that involves federal, state, and local officials; utilities; and emergency responders and planners, while smaller events may only involve utilities and their regulators.

Figure 14. Reliability-Resilience Event Continuum



Resilience planning involves assessing the potential distribution system impacts from major resilience events, while reliability planning focuses on maintaining or improving a distribution system's performance in relation to minor outages as measured by the IEEE 1366 reliability metrics (e.g., CAIDI, SAIDI).

2.4.3.1 Resilience Analysis

Resilience is a characteristic of a system's ability to withstand an impact from cyber and physical threats. Resilience is often used to describe both a major grid damage and outage event and the engineering characteristics of a grid. In planning, both definitions are used to first identify the potential threats and impacts and then the potential solutions to mitigate those threats through prevention, survivability, and recovery.

While distribution reliability assessments have traditionally been performed annually, states and utilities have sought to enhance distribution resilience and conduct these assessments more frequently. Resilience planning is a major consideration within the context of an overall risk management framework that includes threat (event) identification and assessment, risk strategy formulation, and active risk management. Specific threats to distribution systems are uniquely localized within a service area as opposed to bulk power system events that may impact an entire service area or region. Within distribution systems, resilience events may have different scale and scope of impact as well as outage durations.

Ultimately, both resilience and reliability planning efforts inform potential grid investments, including those related to modernization, to address the needs identified. It is also possible to identify grid modernization investments that address both reliability and resilience needs; this is discussed in greater length in the architectural platform discussion in Chapter 3.

The planning process for a more resilient distribution grid can be generalized across the country. States and communities have begun working with utilities to define resilience criteria for their locations; these criteria can then inform general grid modernization strategies and subsequent technology deployment plans. Assessing threats and determining prioritized strategies for addressing them—e.g., applying microgrids to sustain the operation of critical facilities—will serve as inputs to an effective planning process. Determining what new grid configurations may be deployed will inform functional and structural requirements associated with grid modernization investments.

The Electric Power Research Institute (EPRI)[15] describes resilience planning as a three-pronged approach in terms of prevention, survivability, and recovery:

- **Prevention:** Preventing damage in the distribution system requires changes in design standards, construction guidelines, maintenance routines, and inspection procedures using innovative technologies.
- **Survivability:** The ability to maintain some basic level of electrical service using resilient technologies to critical consumers or communities in the event of a complete loss of electrical service from the distribution system.
- **Recovery**: Rapid damage assessment, flexible grid designs, prompt crew deployment to damaged assets, and readily available replacement components.

Fundamental to resilience planning is determining a risk strategy integrated with the approach above. This involves determining the risk associated with threat impacts, determining the appropriate risk tolerance and related strategic approach for accepting certain level of risks, mitigating the impact of certain risks, and enabling the avoidance of other risks. These strategies for various risks inform the development of various grid, customer, and third-party solutions.

Resilience planning, as described, is part of a larger lifecycle that incorporates learning from past system events to enable the development of proactive approaches (e.g., system hardening). This lifecycle spans planning, operations, and post-event evaluation. The planning steps are consistent with and integral to the overall planning process, and the solution prioritization in conjunction with overall cost-effectiveness is described in Chapter 5.

2.4.3.2 Reliability Analysis

Reliability planning, conversely, is typically evaluated in the context of performance based on reliability indices in IEEE 1366 that reflect the annual average duration and frequency of outages experienced by utility customers as well as other key performance indicators by feeder, region, and service territory. This performance assessment also usually includes identifying worst-performing circuits and conducting associated root cause analysis.

For example, Ohio's utility code on distribution circuit performance[16] requires an annual performance report that provides information for each reported worst-performing distribution circuit (i.e., the worst 8 percent of all circuits), including:

- Location of the primary area served by the circuit
- Approximate number of customers on the circuit by customer class
- Circuit ranking value
- Each circuit's service reliability indices; the System Average Interruption Frequency Index (SAIFI), CAIDI, and SAIDI
- Number of safety and reliability complaints
- Number of critical customers on the circuit
- Any major factors or events that specifically caused the circuit to be reported among the worst performing circuits and, if applicable, the analysis performed to determine those major factors

Additionally, Ohio requires an action plan for all remedial action taken or planned to improve these worst performing circuits to a level that removes the circuit from the annual report.

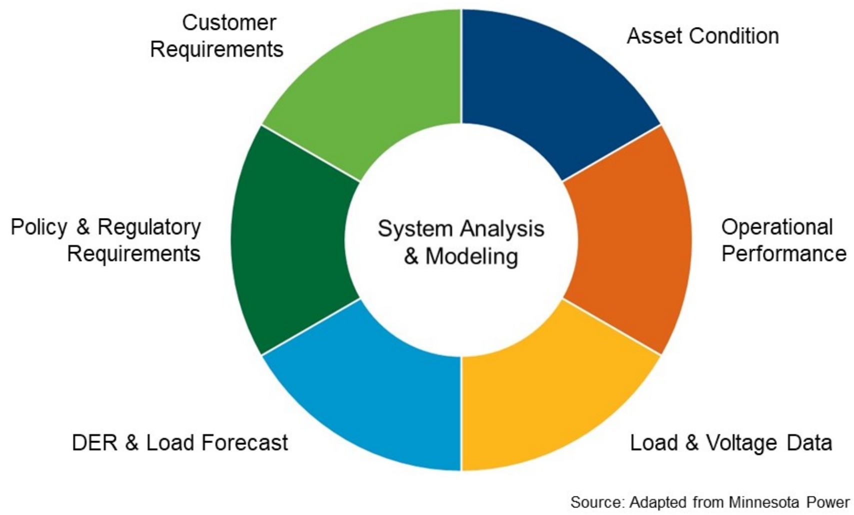
Most utilities conduct similar, detailed engineering analyses on the worst-performing circuits to identify root causes of poor performance and service interruptions. These analyses include location and duration of the interruptions, number of customers affected, root causes (e.g., weather events, equipment failure, animal contact, human contact), and physical environmental characteristics (e.g., surrounding vegetation) of the circuits.

Failure analyses are typically conducted on equipment that has failed prematurely. Failures are a regular occurrence to be expected on vast electric distribution systems that contain many pieces of equipment. Utilities generally have refined processes around equipment failure analysis, and many have either invested in their own facilities to conduct testing and analysis or have contracted with independent facilities, such as through EPRI. Each failure provides an opportunity to learn about its causes and to apply these learnings to prevent new failures.

2.4.4 System Analysis

The laws of physics ultimately dictate the physical operation of the electric system; planning system upgrades involves a rigorous power flow analysis of the current system based on the planning objectives and criteria, forecasts, system condition, and related operational data, as illustrated below. The purpose of the **system analysis** is to ensure that the distribution system can meet customer demands, including electrification, and that DER and related services can be integrated into the system while maintaining safety and power quality within established standards. Inputs to the system analysis are shown in **Figure 15** below.

Figure 15. Inputs to System Analysis



A system analysis involves conducting five critical assessments:

1. Thermal loading analysis
2. Power quality analysis (primarily voltage levels)
3. Protection analysis
4. Contingency analysis
5. Hosting capacity assessment, based on forecasts of load and DER adoption

2.4.4.1 Thermal Loading Analysis

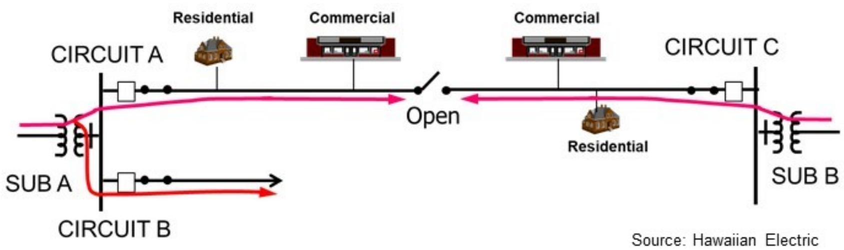
Thermal loading analysis includes assessing forecasted equipment loading in the context of equipment and conductor ratings for both normal and contingency conditions based on power flow in either direction. Distribution system conductors and equipment have normal and emergency loading limits. These may include current carrying capability (ampacity) as well as temperature and fault- current limits. Exceeding these limits stresses the system, may cause premature equipment failure and related safety concerns, and may result in customer outages. Distribution planning processes primarily focus on the substation and feeder levels, but they also consider limitations and utilization of individual system components such as cable, conductors, circuit breakers, transformers, field switches, and others. The result of these location-specific planning studies is an identification of system/operational needs defined in engineering terms.

2.4.4.2 Power Quality Analysis

Power quality analysis, primarily voltage analysis, examines the impact of loading levels on overall feeder voltage and on the voltage for specific customers under normal and outage conditions when circuits are reconfigured. This is done by assessing voltage quality, within the applicable ANSI standard, based on the equipment and control systems required to maintain customer nominal voltage, and customer exposure to an outage contingency based on the length of the reconfigured feeder from the substation transformer to the customer. Harmonic analysis is typically done on an as-needed basis; for example, in specific instances of unusual customer device/equipment characteristics.

As illustrated in **Figure 16**, this analysis is conducted to ensure that the current flowing through distribution equipment does not violate the planning criteria for thermal loading of equipment during normal conditions and ensure voltage is maintained within defined service quality standards (i.e. ANSI C84.1 Range A and B)[17] in any of the time periods studied.[x] Voltage issues can arise on both the distribution primary (e.g., 4kV, 12kV, 21kV) and secondary (e.g., 480v, 240/120v) voltage systems.

Figure 16. Normal Distribution Conditions



2.4.4.3 Protection Analysis

Protection analysis for distribution systems with high DER and/or microgrid development will be an important consideration in the system analysis because the output of distributed generation or storage resources can cause mis-operation of distribution protection systems that lead to failures. For example, when there are high levels of distributed generation on a feeder, protective equipment such as reclosers or substation relays may not operate as intended because they are unable to differentiate between loads, distributed generation, and a system fault. Should this occur, there is a risk that a faulted portion of the system would remain energized and present a public safety hazard.

2.4.4.4 Contingency Analysis

Contingency analysis evaluates distribution conditions when outages occur, and alternative transformers and/or circuits are then used to restore all or a portion of the load. Metropolitan radial distribution systems are often designed to withstand planned and unplanned contingency or emergency situations to enhance reliability and resilience. **Figure 17** illustrates an emergency condition involving a substation transformer. A distribution planning criterion for these situations may state that a substation transformer will have certain level of capacity to not only accommodate the highest peak demand (or other loading criteria) and any forecasted load growth, but also accommodate a certain percentage of additional transferred load from the loss of a neighboring substation transformer.

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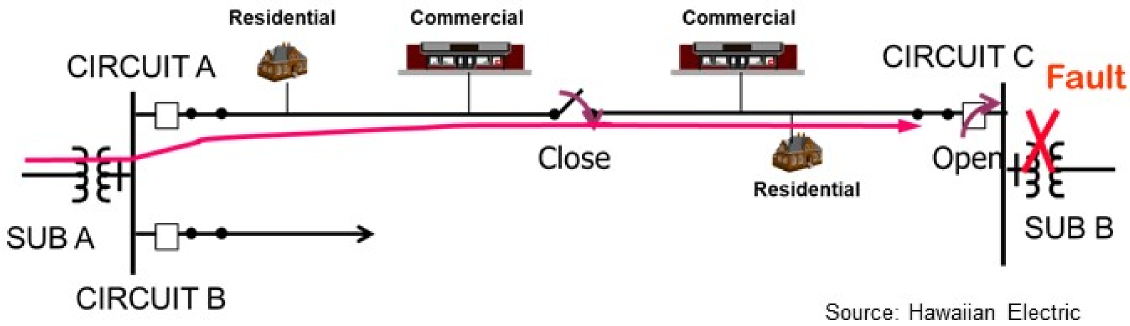
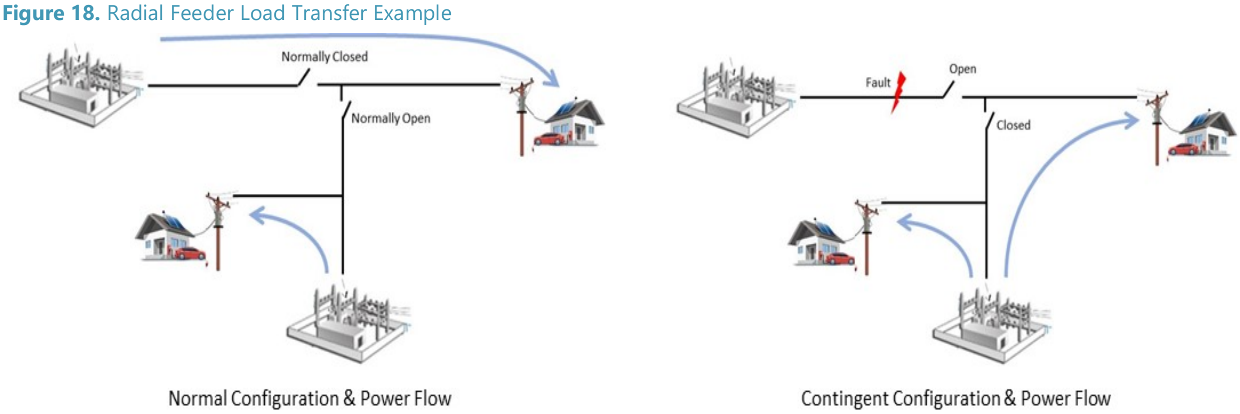
[x] The American National Standard for Electric Systems and Equipment (ANSI C84.1-2011) establishes optimal and acceptable voltage ranges for 60-Hz electric power systems. See: http://www.powerqualityworld.com/2011/04/ansi-c84-1-voltage-ratings-60-hertz.html.

Figure 17. Distribution Contingency Analysis



In another example, the load of one circuit that has a fault is picked up by an adjacent circuit(s) through back-tie switches, as illustrated in **Figure 18**. Similarly, the circuit planning criteria for these types of circuits will typically reserve some capacity to pick up the load switched from the faulted circuit. This capability is also used in routine switching for maintenance. In this context, the utilization of substation transformers and circuits must be balanced between maximizing the utilization and reserving capacity to be able to switch sections of circuits, thus providing the operational flexibility to provide resilience and reliability.

Figure 18. Radial Feeder Load Transfer Example



As an example of the above, Xcel Energy[18] describes their capacity loading analysis and related risk assessment:

> "One of the main deliverables of distribution planning's annual analysis includes a detailed list of all feeders and substation transformers for which a normal overload (N-0) is a concern. A normal overload is defined as a situation in which the real time load of a system element (conductor, cable, transformer, etc.) exceeds its maximum load carrying capability.
>
> "Additionally, distribution planning delivers an N-1 Contingency Analysis, which is a list of all feeders and substation transformers for which the loss of that feeder or transformer results in an overload on an adjacent feeder or transformer.
>
> "This process of identifying N-0 overloads and N-1 risks for feeders and substation transformers is referred to as distribution planning's annual 'risk analysis.' The total number of risks identified in the risk analysis generally exceeds the number of risks that can be mitigated with available funds. There is always a balance that we must strike in mitigating

risks, planning for new customers, and addressing both the aging of our system – as well as preparing it for the future."

This type of capacity analysis is typical of industry practice and is the basis for identifying capacity needs and subsequent development of mitigation plans that may include grid modernization technologies[19] or DER reliability services as alternatives to poles and wires infrastructure investment.

2.4.4.5 Hosting Capacity Analysis

Hosting capacity analysis estimates the amount of DER that can be accommodated, regardless of location, on a sub-transmission distribution system, substation, or a feeder without violating power quality, thermal loading, or protection requirements. The distribution planning analysis evaluates these three dimensions against distribution planning criteria. The evaluation of equipment capacity and operational flexibility is no different than the process described above for traditional one-way flow of power to serve load except that the hourly loading and DER output patterns may be different.

Hosting capacity has largely been discussed in terms of interconnection assessment, but forecasting hosting capacity analysis can also inform the planning process and identify circuit constraints to be resolved to facilitate DER growth.[20] Further, to the extent that distribution-connected DER provides wholesale energy services, it is necessary to consider the deliverability of that DER across the distribution system to the wholesale transaction point.

2.5 Near-Term and Long-Term Distribution Planning

2.5.1 Near-Term Distribution Planning

A best practice for utilities is an annual planning effort that focuses on determining the one- to two-year incremental grid needs and areas for operational performance improvement. This planning process is used to refine internal utility capital and operational budget allocations and define specific project and program activities for the following year. This tactical planning effort involves combining the results of asset condition assessment, resilience and reliability analyses, and the system analysis to begin the process to identify potential remediation, mitigation, and upgrade solutions. Annual planning is also informed by the longer-term strategic roadmap and considerations in a corresponding IDP.

2.5.2 Long-Term Distribution Planning

Long-term distribution planning is more strategic in nature and is undertaken to understand the potential major grid changes that may be needed and any adjustments to ongoing programmatic efforts. Long-term plans are largely focused on identifying and assessing the large impacts to an existing distribution system design and determining the performance and any needed longer-term changes that will be necessary. This includes, for example, addressing threats to resilience and large-scale DER and microgrid integration, utilization, and electrification, as well as the socioeconomic conditions that major grid changes will create. This contrasts with the near-term plans that are focused on specific immediate grid needs and tactical projects that are required within two years.

Longer-term distribution planning, beyond the electric system analysis discussed for near-term planning, may involve three additional efforts: 1) scenario-based studies of distribution grid impacts to identify grid needs; 2) a solutions assessment including potential operational changes to system configuration based on new design standards or resilience improvements, programmatic infrastructure replacement, upgrades, and modernization investments; and 3) potential for non-wired alternatives. The cyclical long-term planning effort should also consider potential changes to programmatic asset plans, as well as opportunities to optimize distribution upgrade and modernization plans.

2.5.2.1 DER and Microgrid Considerations

Historically, distribution planning was often done outside the context of integrated resource planning and transmission planning. To the extent that DER is considered in resource and transmission planning, it is essential to align assumptions concerning DER and load-growth patterns, with respect to timing and net-load shape assumptions with those used for distribution planning. As discussed, these growth patterns will drive the grid modernization investments needed to address the complex planning and operational challenges posed by increasing levels of DER and requirements to sustain security, resilience, and reliability.

To the extent that distribution-connected DER provides wholesale energy services, it is necessary to consider the deliverability of DER services (e.g., energy, capacity, and ancillary services) across the distribution system to the wholesale transaction point. A variation of forecasted hosting capacity analysis, for example, may be used[21] to assess the grid needs to support the use of energy and grid services from DER, including portfolios of various DER as well as customer/third-party-owned microgrids. Additionally, at high levels of DER adoption, the net load characteristics on the distribution system can have material impact on the transmission system and bulk power system operation.[xi] As a result, planning studies should incorporate longer-term contingency analyses to identify high-risk areas—including those occurring at the transmission-distribution interface—and determine where application of DER may improve overall safety, reliability, and resilience. Therefore, the interdependencies of resource and transmission plans with reliability and resilience expectations should be considered.

Microgrids (including mini-grids) may play an important role in creating a resilient electric system in certain states; thus, it is crucial to keep in mind that microgrids during normal conditions are often designed to provide export energy for sale into the power system and provide ancillary and other grid services. Many microgrid developments require the ability to provide these services as a part of their economic assessment. Therefore, consideration of the contribution of DER and microgrids should be factored into IRP, transmission, and distribution system planning processes, giving credence to the dependent interrelationships between them.

Microgrids, customer back-up generation, grid hardening, and modernization are all potential solutions for achieving a resilient power system. However, one key challenge is determining the desirable mix of community-wide solutions (e.g., cyber-physical grid hardening, mini-grids, and multi-user microgrids) versus point solutions (i.e., customer initiated technology adoption such as solar/storage, back-up generation, energy storage, customer microgrid) as illustrated in a solutions map (**Figure 19** below).

[xi] "Net load" here refers to the amount of load that is visible to the TSO at each T-D interface, which can be expected to be much less than the total or gross end-use consumption in local areas with high amounts of DERs. The term "net load" is also used at the transmission system level to refer to the total system load minus the energy output of utility-scale variable renewable generation, as illustrated by the CAISO's well known "duck curve." In this report we are focusing mainly on the first sense of the term—i.e., the impact of DERs on the amount of load seen at each T-D interface.

Figure 19. Resilience Solutions Map

A portfolio approach, which suggests the need for more coordinated planning, may be needed to efficiently achieve desired outcomes, as specific point solutions do not necessarily address needs all on their own. Typically, customer-based, point solutions address specific needs that may be based on improved resilience and economic efficiencies; collectively, the point solutions may not achieve the societal benefits intended by government policies in an effective or efficient manner. Engaging community and third-party microgrid developers, with active participation of the utility, should also be considered to ensure that a coordinated approach to microgrid and DER development is aligned with IRP and distribution investment plan objectives in order to achieve an appropriate portfolio that ensures the overall affordability, resilience, and efficiency desired.

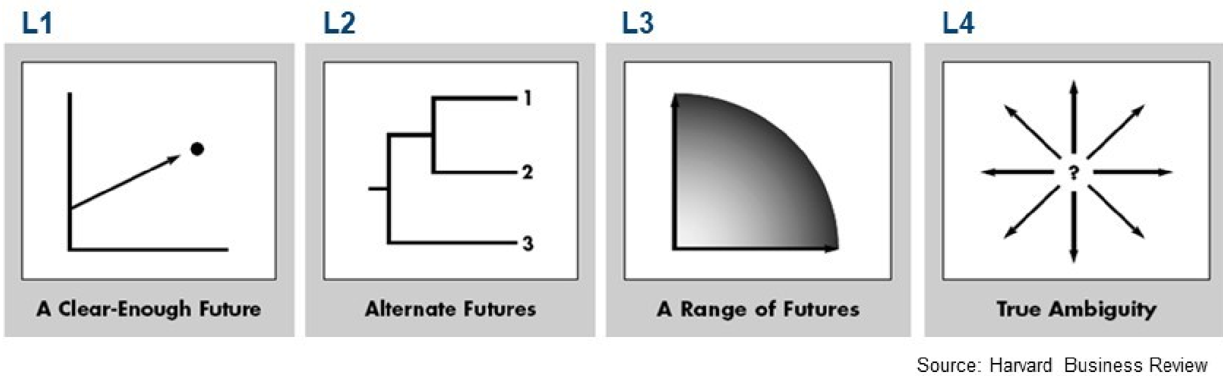
At the highest level of technical complexity is a grid topology that allows for parts of the system to isolate, operate independently, and reconnect. This is true of utility community microgrids and especially so for third-party community, multi-user microgrids—although no known developments are being developed in the United States. There are some examples of utility community micro-grids that can operate in this fashion, but they come at a relatively high cost in terms of engineering and financial resources needed to plan, build, and operate them. Nevertheless, there is a growing interest in the application of such microgrids to improve resilience, and planning processes will thus need to consider them.

2.5.2.2 Scenario-Based Studies

Distribution studies beyond the three-year horizon are inherently uncertain and complex given the underlying forecasts for load changes, DER adoption, microgrid development and electrification. Therefore, using several potential scenarios can be helpful to inform strategic direction in longer-term distribution plans.

As shown in **Figure 20.** Four Levels of Uncertainty below, there are various methods to help assess different levels of uncertainty ranging from a discernable future to one that may offer many potential pathways. Level 1 involves the use of deterministic “point” forecasts. This is the approach distribution planners historically used in planning. As uncertainty increases (e.g., DER adoption, EV adoption and charging preferences, customer response to time varying rates), as is occurring on many distribution systems, deterministic forecasts alone will no longer be viable for distribution planning. In response, many planners are incorporating assumption sensitivities and alternative scenarios (Level 2) related to the factors mentioned above. Alternative scenarios are effective for most distribution systems experiencing/anticipating higher DER/EV adoption over the next decade.

Figure 20. Four Levels of Uncertainty



However, for some distribution systems, DER adoption and the potential changes in customer load are far greater, as experienced in Hawaii and California. A Level 3 analysis would involve probabilistic techniques to consider a range of potential futures; this is significantly complex and difficult to do properly. For example, sufficient information about each of the base forecast assumptions is needed to develop range estimates, and temporal aspects are needed to fully inform the results used to conduct the engineering assessments of substations and individual circuits.

Scenario-based longer-term planning (Level 2) enables a robust consideration of the timing and magnitude of investment, including grid modernization, needed over a 5–10-year period. A Level 2 analysis supports the development of grid modernization strategies and related roadmaps that shape subsequent implementation plans, which are presented in more detail in Chapters 3 and 4. As these longer-term plans are routinely updated every one to three years, there is an opportunity to update the associated grid modernization strategies to reflect changes in customer adoption of DER, advancement of technologies, policies, and other key factors.

In recognition of these factors, utilities are increasingly required to perform long-term distribution planning processes every two to three years with a 5–10-year planning horizon in line with an IRP. Longer-term plans particularly benefit from stakeholder engagement on planning assumptions, planning methods and process, and discussion of results through a more transparent process.

2.5.3 Near-Term Distribution Asset Management and Major Capital Planning

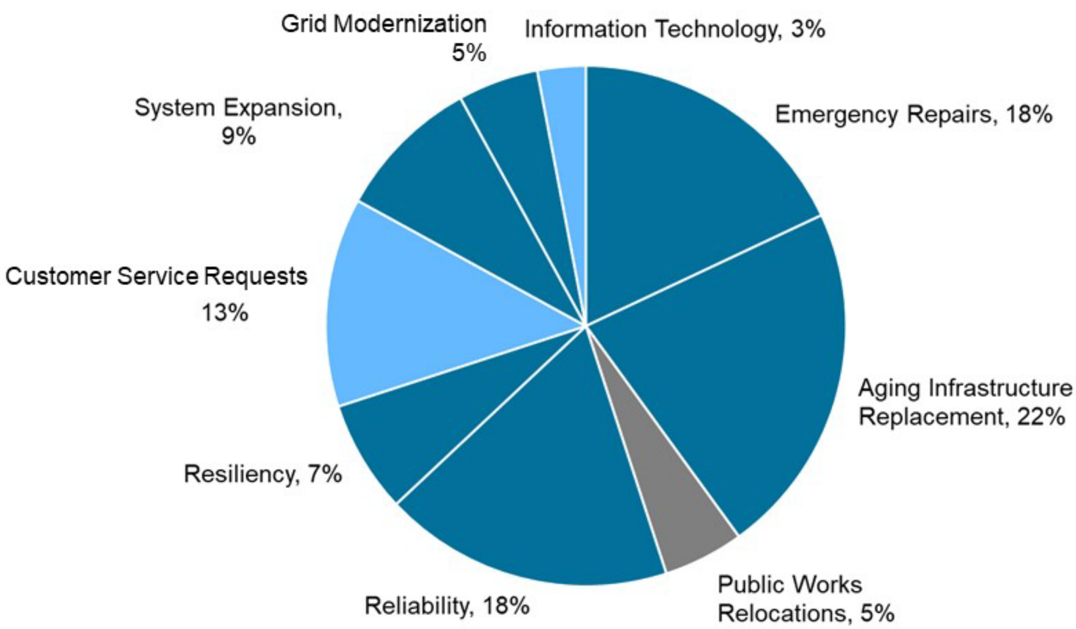
Annual and longer-term planning analyses function similarly to analyses of asset condition, resilience and reliability, and system capabilities to identify specific grid needs. These engineering needs provide the basis for identifying **solutions** that must satisfy the engineering needs identified as well as other key criteria such as capital budget limits. There are two categories of solutions that are generally considered by utility planners: 1) operational changes and minor near-term capital investments and 2) major capital investments.

The first category of solutions may be as simple as reconfiguring a feeder by transferring part of the load to another feeder or balancing the loading of a feeder by moving service transformers to a different phase.[xii] Other simple solutions related to protection scheme and voltage management settings, as well as minor equipment replacements, can be readily accomplished in the near term and resolve a number of grid needs related to changes in net-load shapes and variability, as well as bi-directional power flows associated with certain DER.

These solutions do not solve all typically identified distribution system needs. Major capital investments will also be identified to address grid needs, including grid modernization technologies. The net result of annual and long-term planning, including consideration of non-wires alternatives (NWAs),[22] will be a portfolio of distribution grid and operational projects that form the basis for near-term action plans (including annual plans) and longer-term strategic roadmaps.

These projects typically fall into one of the following categories, which compose a utility's annual capital budget, as shown in **Figure 21** and described below. Note that those investment areas shaded in blue relate directly (dark blue) or indirectly (light blue) to forming the resilience of the distribution system.

Figure 21. Typical Utility Capital Budget Composition



Aging Infrastructure Replacement

Replacing infrastructure experiencing high O&M costs and/or failure rates, as well as aging infrastructure that should be prudently replaced. Replacement is typically not "like for like," as utilities seek to incorporate new design standards.

[xii] Distribution feeders, unlike transmission lines, are not typically operated with balanced load across the three phases.

Resilience and Reliability Upgrades

System enhancements to improve a distribution system's ability to withstand and mitigate the impact of major events caused by nature and/or humans, as well as the performance of the system (e.g., improving the reliability of worst-performing feeders).

Emergency Repairs

Includes infrastructure replacements due to storms and public damage (e.g., car accidents damaging poles, dig-ins).

Customer Service Requests

The provision of service to new customers through installation or expansion of feeders, primary and secondary extensions, and service laterals.

Capacity Upgrades

Increases in infrastructure capacity through voltage upgrades, new substations, and circuits to support load growth and/or DER adoption/development on the system and to improve operational switching flexibility.

Public Works Requests

Typically includes projects to relocate utility infrastructure in public rights-of-way such as road widening or realignment.

Modernization

Includes advancements in grid sending, communications, control, information management, computing, and coordination capabilities to enable improved distribution resilience/reliability, operational efficiencies, and integration and utilization of DER and microgrids.

The expense of capacity upgrades, reliability measures, and certain capital investments may provide the basis for considering NWAs to offset overall system costs. Several states and utilities have developed guidelines for identifying and evaluating NWA opportunities.[23] If NWA are to be pursued, such efforts will likely involve investment in grid modernization functionality discussed in Chapter 3. The net result of near-term and long-term planning, including consideration of NWAs, will be a portfolio of grid modernization investments that form the basis for an implementation plan discussed in Chapter 4.

2.6 Performance Evaluation

The cycle of design to project completion can range from several months to multiple years based upon the scope and scale of work. Distribution planning organizations are typically responsible for tracking the status of proposed and approved projects as they progress through the construction process. Upon project completion, these organizations should provide updates to asset and operational databases, such as the GIS database, in order to document asset changes and help facilitate the quality of system data models for use in operational tools and future engineering planning cycles. Additionally, post-project evaluation of a system's efficacy and performance is conducted annually as part of the system analysis. These annual evaluations inform the longer-term plans both in terms of progress toward longer-term objectives, remaining gaps, and lessons learned during implementation to inform future projects.

3. Modern Grid Strategy Development

3.1 Chapter Summary

This chapter introduces a sequence of activities to develop a customer-oriented grid modernization strategic plan that traces needed functionality to identified customer, policy, and business objectives resulting in an architecturally sound strategic roadmap. This Guidebook emphasizes the need to develop a grid modernization strategy that incorporates both functional and structural features needed over time.

CHAPTER OUTLINE

- 3.2: Elements of Strategy Development
- 3.3: Mission, Principles, & Objectives
- 3.4: Capabilities & Functionality
- 3.5: Grid Architecture Considerations and Strategies
- 3.6: Strategic Roadmap
- 3.7: Timing of Strategy Development Activities

KEY POINTS

This chapter includes a discussion on:

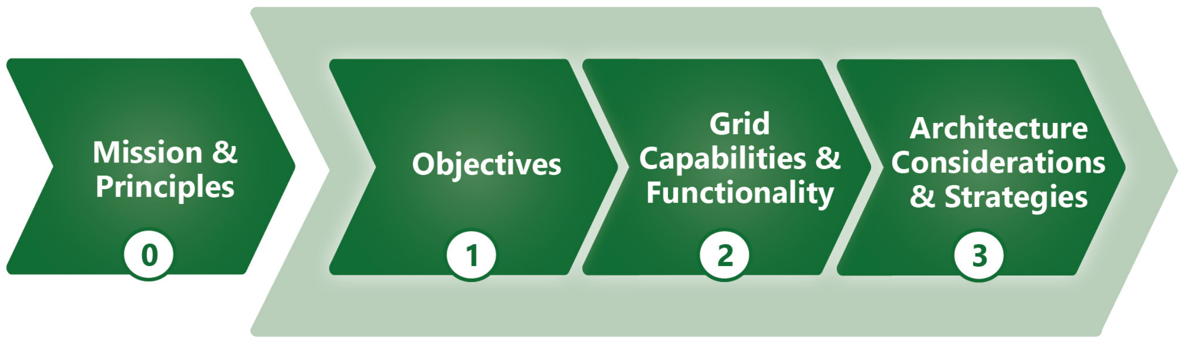
- Planning principles and objectives, with examples
- The DSPx taxonomy (discussed in detail in Volume I) including a set of capabilities and functions associated with grid planning, operations, and market operations
- Grid architecture principles, considerations, and associated strategies
- Developing a strategic roadmap and supporting cost estimates

3.2 Elements of Strategy Development

Grid modernization strategy development combines strategic planning techniques with grid architecture considerations to guide development in the first four steps of the planning process—Identify Mission & Principles (outlined in **Figure 22.** Steps 0-3 of Grid Modernization Planning Process):

0. Develop Mission Statement and Principles
1. Determine Grid Modernization Objectives
2. Identify Grid Capabilities & Functionality Needed (Taxonomy)
3. Identify Grid Architecture Considerations & Develop Strategies

Figure 22. Steps 0-3 of Grid Modernization Planning Process



Each of these steps are whole processes unto themselves and will be outlined in this chapter. The "**Objectives**" step typically involves a stakeholder process to determine planning objectives based, if possible, on higher-level goals often articulated through a mission statement and formal set of principles.

The "**Grid Capabilities and Functionality**" step is a utility-derived process involving the application of the DSPx taxonomy with stakeholder feedback. This step should result in the determination of grid capabilities and functions needing to be implemented over a certain timeframe.

The resulting set of functional requirements, with an understanding of the current grid design, serve as the basis for a system-wide structural analysis undertaken by the utility in the "**Architecture Considerations and Strategies**" step.

Undertaking these steps should inform the development of a conceptual solution roadmap and cost estimate. Each of these steps informs the other over time. Determining the respective roles and responsibilities of regulators and utilities in performing, reviewing, and approving these steps is based upon the preferences of a particular jurisdiction.

3.3 Mission, Principles, & Objectives

3.3.1 Mission and Principles

The starting point for a grid modernization effort is to reference a jurisdiction's or utility's existing **mission** and **guiding principles**. In some cases, a jurisdiction or utility may have developed a set of guiding principles specific to grid modernization. In either instance, these principles provide the foundational reference for the logical structure of the functional taxonomy. Principles serve to inform the development of objectives and subsequent strategies and plans.

An example of jurisdictional principles from the Missouri Public Service Commission:[24]

Missouri Public Service Commission Jurisdiction Principles:

"We will:

- *ensure that Missourians receive safe and reliable utility services at just, reasonable and affordable rates;*
- *support economic development through either traditional rate of return regulation or competition, as required by law;*
- *establish standards so that competition will maintain or improve the quality of services provided to Missourians;*
- *provide the public the information they need to make educated utility choices;*
- *provide an efficient regulatory process that is responsive to all parties, and perform our duties ethically and professionally."*

A jurisdiction's mission statement may also provide the foundation to the start of a grid modernization effort, such as the example below from the Public Utilities Commission of Ohio (PUCO):[25]

Public Utilities Commission of Ohio Mission Statement:

"The PUCO was created to assure Ohioans adequate, safe and reliable public utility services at a fair price. More recently, the PUCO gained responsibility for facilitating competitive utility choices for Ohio consumers."

The CenterPoint Energy's corporate vision,[26] as another example, is below.

CenterPoint Energy Corporate Vision:

Lead the nation *- We are committed to performing at a level that will make us America's premier energy delivery company.*

Delivering energy *- Delivering safe, reliable and efficient energy is our core business. We'll make smart investments in reliable and resilient equipment and technology.*

Delivering value *- We'll deliver customer-focused services that complement our energy delivery capabilities.*

These types of overarching principles and mission statements may in turn be used to define a set of guiding principles for grid modernization strategy and planning development. As an example, the guiding principles below were adopted in Hawaii:[27]

Hawaiian Electric Companies' Guiding Principles to Inform Grid Modernization

- *Enable greater customer engagement, empowerment, and options for utilizing and providing energy services.*
- *Maintain and enhance the safety, security, reliability, and resiliency of the electric grid, at fair and reasonable costs, consistent with the state's energy policy goals.*
- *Facilitate comprehensive, coordinated, transparent, and integrated grid planning across distribution, transmission, and resource planning.*
- *Move toward the creation of efficient, cost-effective, accessible grid platforms for new products, new services, and opportunities for adoption of new distributed technologies.*
- *Ensure optimized utilization of resources and electricity grid assets to minimize total system costs for the benefit of all customers.*
- *Determine fair cost allocation and fair compensation for electric grid services and benefits provided to and by customers and other non-utility service providers.*

Each jurisdiction or utility[28] will have very specific principles, missions, or grid modernization guidelines in relation to their situation and needs. The examples above are provided only to illustrate the type of information that may exist or could be developed to shape the direction of grid modernization.

3.3.2 Objectives

Grid modernization planning is a rigorous engineering-economic activity that should be driven by clear objectives; otherwise, it becomes difficult to assess whether resulting plans are responsive, and key stakeholders may not accept them.

It is important for each jurisdiction or utility to define the scope of grid modernization through a unique set of objectives based on their guiding principles and timing considerations with respect to DER adoption and resilience concerns. Objectives are associated with improving existing capabilities or adding new ones, often related to improving customer experience or system characteristics. In this context, **an objective is a goal or outcome with an associated timing and/or performance metric**. For example, objectives may include a) specific customer, policy, and/or business outcomes and b) associated timing and/or performance requirements. Objectives inform what is needed by when and guide the subsequent steps in the process. In practice, identifying objectives or goals without an understanding of the price tag is a significant challenge and has led to sticker shock. Chapter 5 on grid modernization economics discusses an approach to address this problem. A cost estimate determined from the conceptual roadmap in the strategy process will help better understand associated cost.

Figure 23 consolidates the categories developed in prior DSPx work (see Volume I) into a single list of objective categories with "enable electrification" added as a revision. This is offered as a reference to use in developing jurisdiction/utility-specific objectives that may align to these or to other categories, owing to each jurisdiction's and utility's unique set of circumstances.

Figure 23. Revised Reference Objective Categories

Affordability	Operational Excellence
Safety	Enable DER Integration
Customer Enablement	Reliability & Resilience
System Efficiency	Enable Technology Innovation
Cyber-physical Security	DER Utilization
Reduce Carbon Emissions	Enable Electrification

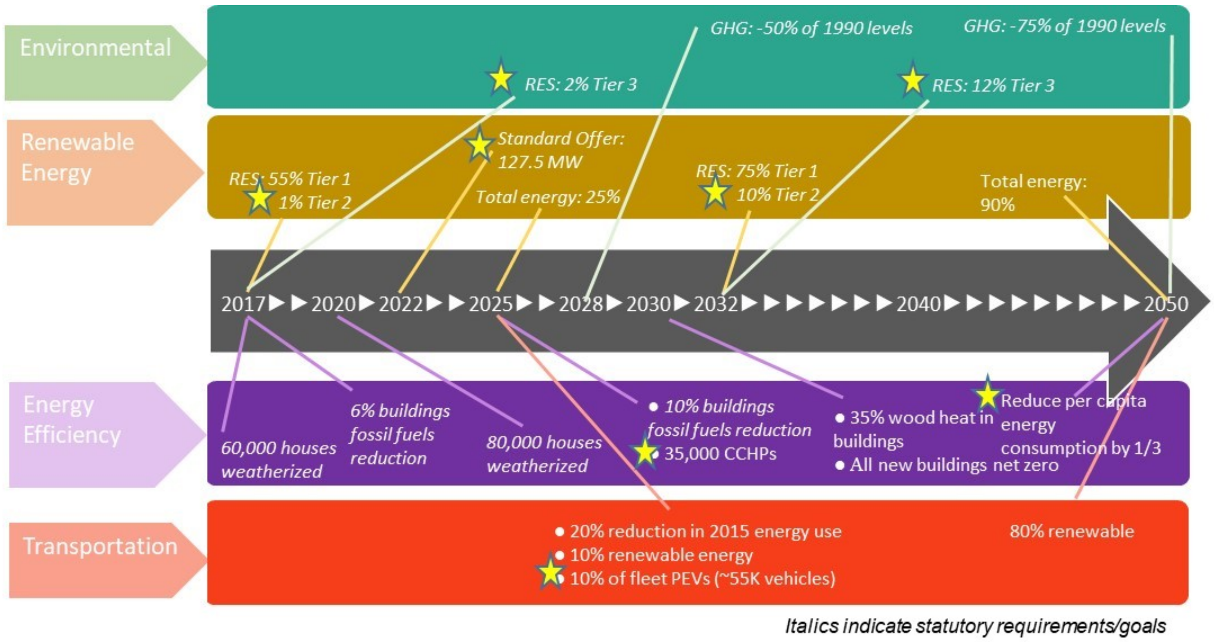
Any strategy or planning effort requires clear direction on *"what"* the desired outcomes are. Planning also needs a sense of *"when"* the outcomes are expected. These timing expectations set an important constraint that informs the later steps in the overall process, which will involve a realistic evaluation of what is achievable within a given timeframe as well as assessing technology maturity in relation to when it is needed. Strategic investment planning of this type, given the relatively long life of grid modernization investments and certain deployments, may benefit from a time horizon of at least 5 years and perhaps up to 15 years.

Grid modernization planning is a rigorous engineering-economic activity that should be driven by clear objectives.

3.3.2.1 Examples from States and Commissions

Objectives can often be derived from legislative and/or executive orders. For example, Vermont's overall policy drivers include clear objectives and timelines with grid modernization implications, shown in **Figure 24**.[29]

Figure 24. Vermont Policies with Grid Modernization Implications



Several states have developed grid modernization objectives that are useful to illustrate how a state may link their principles to clear outcomes with metrics. The following examples are drawn from several states' regulatory guidance documents and utility filings as noted.

In Michigan, the Commission described the overarching objectives for the electric distribution system to help clarify the purpose for requiring the initial round of distribution plans. The objectives listed included: 1) safety, 2) reliability and resiliency, 3) cost-effectiveness and affordability, and 4) accessibility. The definition of certain objectives may expand their scope beyond their chosen title. For example, "cost-effectiveness and affordability" also includes the ability to integrate new technologies in an optimal manner, such as distributed generation and energy storage.[30]

Likewise, PUCO released their PowerForward Roadmap outlining their grid modernization principles and objectives.[31] The objectives from the Roadmap, in the list below, include a combination of the Customer Enablement, System Efficiency, Cyber-Physical Security, Enable DER Integration, Reliability & Resilience, and Enable Technology Innovation objective categories:

Public Utilities Commission of Ohio Principles and Objectives:

- *A Strong Grid: A distribution grid that is reliable and resilient, optimized and efficient and planned in a manner that recognizes the necessity of a changing architectural paradigm.*
- *The Grid as a Platform: A modern grid that serves as a secure open access platform—firm in concept and as uniform across our utilities as possible—that allows for varied and constantly evolving applications to seamlessly interface with the platform.*
- *A Robust Marketplace: A marketplace that allows for innovative products and services to arise organically and be delivered seamlessly to customers by the entities of their choosing.*
- *The Customer's Way: An enhanced experience of the customer's choosing on the application side, whether for reasons arising from financial, convenience, control, environmental, or any other chosen consideration.*

The "safe, reliable, and affordable" components are already included in the PUCO's mission statement, which were incorporated into the principles of the Roadmap.

In some cases, jurisdictions and utilities have also sought to develop a grid modernization scope definition that may be helpful to further clarify what is needed but is not a replacement for clear objectives. In this regard, a modern grid definition describes the scope in the context of the objectives. However, such a definition is not necessary to start grid modernization strategy development and planning.

For example, the California Public Utilities Commission (CPUC) adopted Staff's proposed definition of grid modernization on their Track 3 Decision Order as follows: [32]

California Public Utilities Commission Definition of Grid Modernization:

"A modern grid allows for the integration of distributed energy resources (DERs) while maintaining and improving safety and reliability. A modern grid facilitates the efficient integration of DERs into all stages of distribution system planning and operations to fully utilize the capabilities that the resources offer, without undue cost or delay, allowing markets and customers to more fully realize the value of the resources, to the extent cost-effective to ratepayers, while ensuring equitable access to the benefits of DERs. A modern grid achieves safety and reliability of the grid through technology innovation to the extent that is cost-effective to ratepayers relative to other legacy investments of a less modern character."

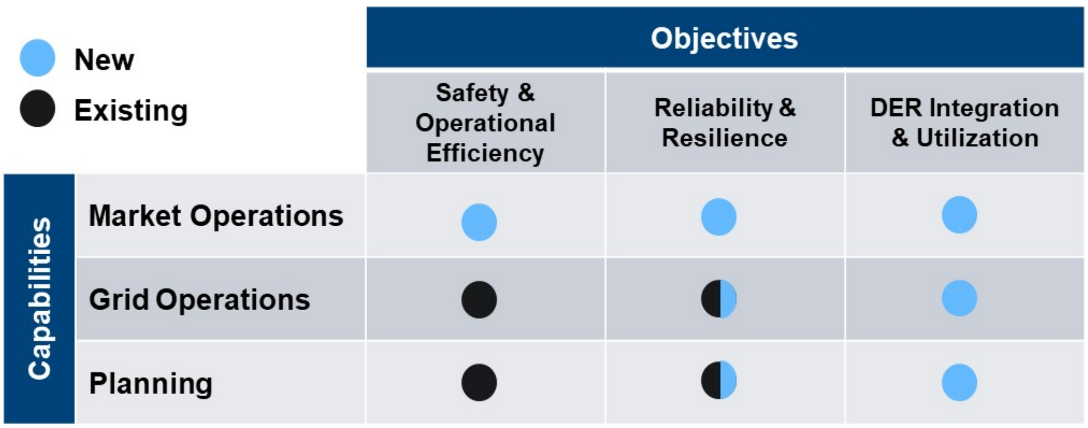
Finally, any grid modernization plan will need to consider resiliency. Note that, while the California grid modernization definition does not include the word "resilient," the CPUC has been very clear that "improving the safety, security, and resilience of utility networks is an unassailably desirable goal."

3.4 Capabilities & Functionality

3.4.1 Capabilities

The next step in the process is to identify the capabilities needed to accomplish the objectives within the defined grid modernization scope. A **capability** is the ability to execute a specific course of action. This extends the consideration of "what" is needed to a higher level of specificity. In simple terms, a capability is the ability to execute a specific course of action. This step involves identifying the needed changes or enhancements to existing capabilities or new capabilities and associated functions, as illustrated in **Figure 25**.

Figure 25. Grid Modernization Capabilities & Functions Matrix



Grid modernization may involve many new capabilities and functions over a period of time, driven by the specific grid modernization objectives discussed above and by the overall integrated distribution planning processes (discussed in Chapter 2). For example, objectives related to reliability and resilience will inform specific planning criteria[xiii] that will then be used to identify gaps and related mitigation measures. Improving the performance of the worst-performing feeders is an example of a measure relating to a reliability objective. In some cases, an objective could be tied to a state goal. For example, one fostering the electrification of transportation (perhaps including tax credits offers or other incentives for electric vehicle); such an objective would inform distribution system forecasts that would change the net loading on a distribution system. These objectives will inform requirements and needed additional capabilities for planning, grid system operations, and markets operations.

Within each grid functional area (i.e., planning, grid operations, and market operations), specific capabilities may be required to meet the stated objectives for that jurisdiction or utility. Each capability

[xiii] Planning criteria are system design and operating parameters established to ensure safe and reliable system operation under normal, transient, and extreme contingency conditions. Such criteria often define requirements for the management of current (thermal limits), voltage, and frequency, as well as service quality to customers. An example of a high-level planning criterion, that would then guide more detailed engineering requirements, is: neither end-use customer load nor interconnected customer generation shall cause any power quality related issues to the utility grid or any utility end-use customer.

can be thought of as a broad “bucket,” containing several underlying technical and business functions, as shown in **Figure 26**.[xiv]

Figure 26. Updated Capabilities Categories

3.4.2 Functions

Capabilities inform what functions are needed. A **function** defines a business process, behavior, or operational result of a process. It is essential that any grid modernization planning identify required changes/enhancements to existing functions as well as to new functions, which include business processes, people, and enabling technologies. In implementation planning, these functions are unpacked through a systems engineering approach to detail the types of activities, processes, information, and interfaces needed. Identifying functions within the context of needed capabilities to meet objectives is a key reference point for any strategic or implementation planning.

A highly simplified set of functional categories is provided in **Figure 27** (planning functions), **Figure 28. Distribution Grid Operations Functions** (grid operations functions), and **Figure 29. Distribution Market Operations Functions** (market operations functions) below.[xv]

[xiv] The updated list of capabilities in Figure 25 is refined from the original in Volume I, Version 1.1. Workforce management has been added, as many aspects of a modern grid require the implementation of 21st century workforce management systems and workforce tools to operate safely and efficiently.

[xv] This list consolidates the prior list of functions and sub-functional elements from Volume I, Version 1.1. In practice, the functional decomposition proved to be unnecessarily complicated for strategic planning purposes. This revised list, organized by functional area, also includes new functions based on industry and regulatory staff feedback.

Figure 27. Distribution System Planning Functions

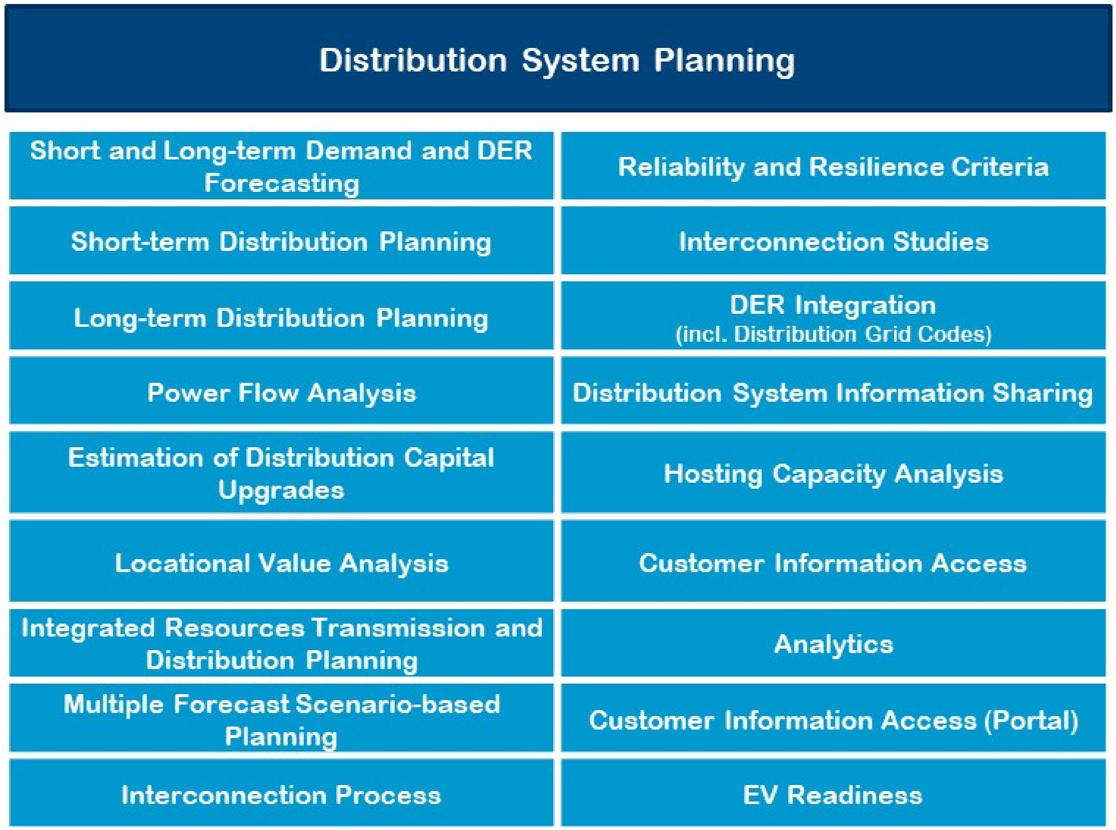


Figure 28. Distribution Grid Operations Functions

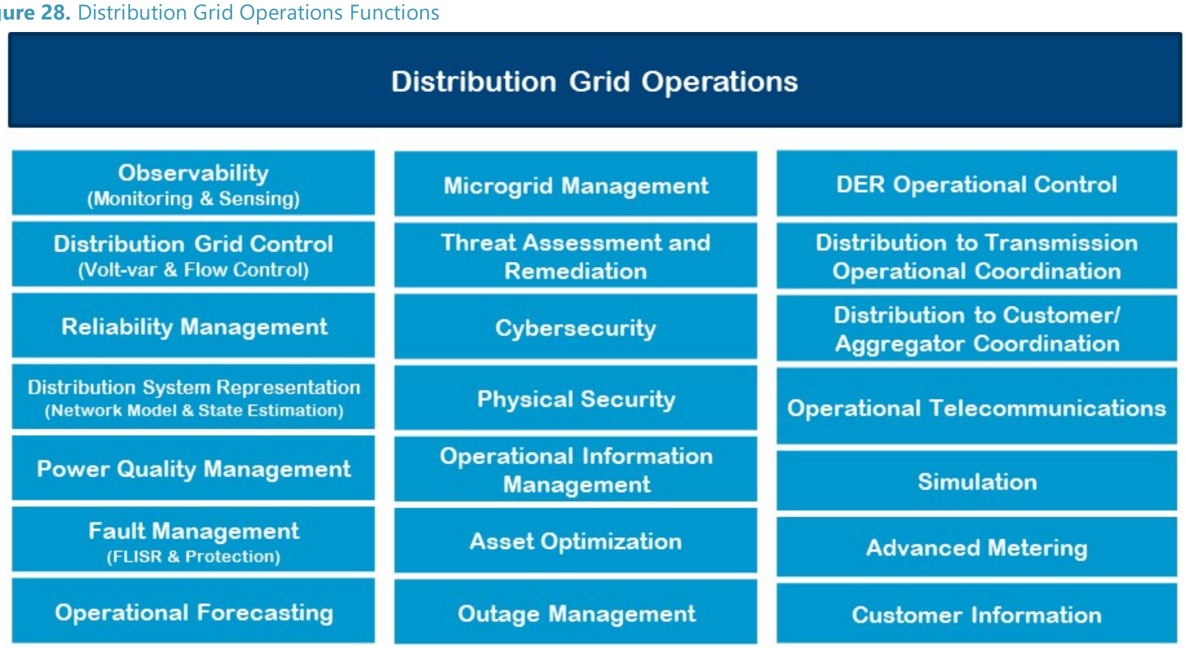
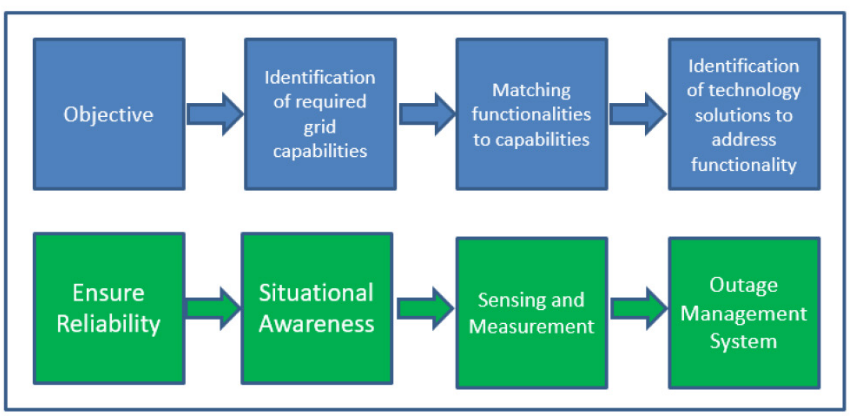


Figure 29. Distribution Market Operations Functions

An example of a logical taxonomic structure was developed by the staff of the New Hampshire Public Utilities Commission and is shown as two examples in **Figure 30**. This figure depicts the logical structure of objectives driving new capabilities regarding customer information access and capability enhancement for outage management, respectively.

Figure 30. NH PSC DSPx Taxonomy Adoption



According to the New Hampshire commission's report, Staff Recommendation on Grid Modernization:[33]

New Hampshire Public Utilities Commission Mapping of Objectives to Capabilities and Functions:

"Staff identifies grid modernizing objectives, selects the capabilities required to achieve them, and develops a list of functionalities associated with each capability to be considered by the utilities to ensure achievement of the objectives."

This "line of sight" reasoning facilitates a robust discussion of the interdependency of technology investments to support objectives. Conversely, if technologies are proposed without regard to objectives, capabilities, and functions, it would be nearly impossible to understand the reasonableness and logic of a grid modernization proposal. This is what is described as *"trying to hang windows first,"* as described in Chapter 1, Figure 2 on page 12.

Examples of taxonomic relationships are provided in **Figure 31**, where technologies are mapped back to objectives. For additional examples, see **Table 1** earlier on page 13.

Figure 31. Examples of Technology Choices Mapped Back the DSPx Taxonomy

Objective	Capability	Function	Technology
Customer Choice through information access for small business & residential customers to support decision making by 2020	Provide online customer access to relevant & timely information	Remote meter data collection & verification Customer data management Energy management & DER purchase analysis	Customer Portal Customer Analytic Tools Greenbutton Smart Meter Telecommunications Meter Data Management System Customer Info System Data Warehouse
Reliability improvement by reducing customer unplanned outage durations Achieve 1st Quartile CAIDI Performance by 2020	Improve outage identification and customer service restoration	Fault Identification Fault Location Fault Isolation Service restoration	Fault Current Indicators Outage Notification from Meters Outage Management System Geospatial Information System Distribution Management System and/or SCADA Automated Switches Work Management System

3.5 Grid Architecture Considerations and Strategies

3.5.1 What Makes Grid Architecture Essential

A significant challenge in dealing with grid modernization is the sheer complexity of the grid. Any technology decision must consider the implications within the context of the larger grid, which can be characterized as an **ultra-large-scale (ULS) system**. A ULS system typically exhibits these defining characteristics:

1. Inherently conflicting diverse requirements
2. Decentralized data, control, and development
3. Continual (or at least long-term) evolution and deployment
4. Heterogeneous, inconsistent, and changing elements
5. Wide-time scales (microseconds to years)
6. Wide geographic scales
7. Normal failures (something is always not working, just as a matter of normal operations)

Natural ecosystems and cities are examples of ULS systems; they are not necessarily designed through top-down engineering, yet are highly complex and organized, made possible by fundamental components, processes, and natural constraints and processes that enable some level of coherent growth.[34] In biological systems, as another example, energy and information management processes provide fundamental support for developing and maintaining cells, individuals, and ecosystems.

The electric grid is transforming rapidly as it becomes more decentralized and integrated with a variety of heterogeneous parts that often have conflicting needs and objectives. It is essential, therefore, that appropriate processes and design considerations are implemented to maintain a stable, coherent, and manageable grid system as it evolves.

What is Grid Architecture?

Grid architecture[35] is an emerging discipline that is concerned primarily with structuring the planning and design of electric systems that manage and distribute electricity. Structure sets the essential limits on what the grid can and cannot do, leading to two important reasons for a focus on grid architecture early in the grid modernization process:

- **Get the grid structure right** and all the pieces fit into place neatly, the downstream decisions are simplified, and investments can be future-proofed.
- **Get the grid structure wrong** and integration is costly and inefficient, grid investments are at high risk of being stranded, and the ability to realize the benefits of modernization may be extremely limited.

Grid architecture uses practices and principles derived from system engineering, network theory, and control engineering to examine the complex relationships associated with the operation of the electric grid and applies that understanding to develop well-reasoned strategies for advancing grid capabilities. A key principle of grid architecture, as defined through work undertaken at the Pacific Northwest

National Laboratory,[xvi] is to gain a holistic understanding of planning objectives and system requirements prior to making decisions to deploy discrete technologies, as certain solutions may not be as robust and enduring as others. For this reason, it is necessary to keep the whole grid context in mind throughout the planning process.

Grid architecture is concerned about the relationships of all the classes of grid structure, including the physical infrastructure, the cyber structure (consisting of sensing, communication, control, information management, and computing substructures), the industry and market structures, the regulatory structure (as regulatory processes impact in very specific ways with grid planning, operations, and market mechanisms), and the convergence of the electric grid with other infrastructures (for example, natural gas, water supply and treatment, and transportation infrastructures).

Grid Architecture Benefits

Grid architecture considerations are highly useful in grid modernization planning processes and help to form an overall strategy that can then guide more detailed engineering designs. An appropriate application of a grid architecture discipline should enable "future-proofing." Grid architecture provides significant benefits, as it:

- Facilitates processes that enable stakeholders to understand the whole system and the implications of change
- Identifies early design decisions to address and potential constraints that "shape" the system
- Identifies and defines key interfaces and platforms
- Manages system complexity and therefore risk
- Facilitates communication among stakeholders (internal and external)

Guidebook Approach to Grid Architecture

A holistic examination of grid architecture is best performed before more detailed system design and deployment. This examination includes two key elements:

1. **Architecture Considerations**: Four key concepts that should be explicitly addressed in an effective grid modernization strategy:
    - Coordination
    - Scalability
    - Layering (including platforms)
    - Buffering (including flexibility)
2. **Architectural Strategies**: Refers to an architectural approach to guide subsequent development of a technical design for certain aspects or components of the grid system, in support of developing an overall grid modernization strategy. These aspects include:
    - Grid structure and circuit topology
    - Operational coordination frameworks
    - Protection and control
    - Observability
    - Data management and analytics
    - Operational communications

[xvi] See the PNNL Grid Architecture Website at https://gridarchitecture.pnnl.gov/ for more information.

- Cyber-physical security

Sections 3.5.2 and 3.5.3 describe these elements in greater detail.

3.5.2 Architectural Considerations

There are several fundamental architectural concepts that all grid modernization planning should consider in the development of strategies and system designs. Objectives for grid modernization are often described in terms of reliability, resilience, flexibility, and interoperability; in fact, there are 80 or more such terms that are often poorly or ambiguously defined.[36]

While grid architecture deals with many of these concepts in detail**, this section of the Guidebook focuses on a core, interrelated set of four considerations that should be explicitly addressed in the development of a grid modernization strategy and/or implementation plans**. Each of these concepts is scalable and can be used at any level of any type of grid system, whether large-scale (transmission-level) or small-scale (microgrid or customer system).

The core four architectural considerations are:

- Coordination
- Scalability
- Layering (including platforms
- Buffering (including flexibility)

3.5.2.1 Coordination

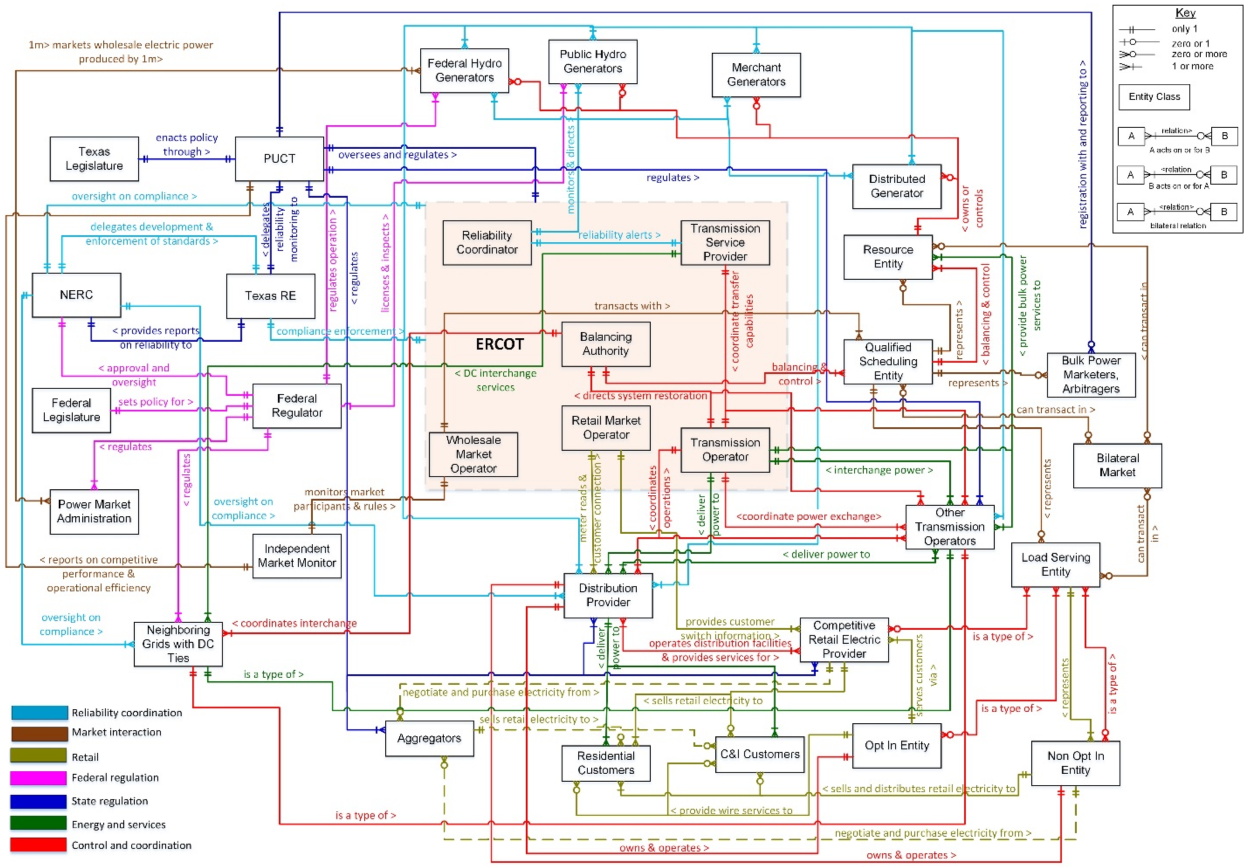
Coordination is a process that causes or enables a set of decentralized elements (which may include devices owned by the utility and assets owned by others) to cooperate to solve a common problem or achieve a specific objective or set of objectives. Grid coordination is the systematic operational alignment of utility and non-utility assets to provide electricity delivery.

Coordination was not a well-recognized issue for electricity distribution until recently due to the rise of DER assets not owned by the utility itself. The advent of a mixed set of DERs owned and operated by entities other than utilities, such as aggregators, shifts the engineering problem from one of *control* to both *control* and *coordination*. Resolving DER coordination has become an industry issue and underlies the current discussions on operational coordination (i.e., across the bulk power, distribution, and customer/third-party domains[37,38]) and models for distribution system operators.[39]

An important first step in determining a coordination framework (i.e., how various devices, assets, and participating entities will cooperate) is to delineate the respective roles and responsibilities of all participants in grid operations and determine their needs and/or capabilities with respect to business objectives, market responsibilities, device or system performance constraints, and data requirements.

Figure 32 is an industry structure diagram showing all the participants in the region managed by the Electric Reliability Council of Texas (ERCOT) and their respective relationships. Within ERCOT, there are 32 discrete entities actively participating in grid planning, operations, and markets as delineated by the various lines of coordination that represent relationships associated with market interactions, state regulation, retail sales activities, the provision of energy and ancillary services, and various control mechanisms.

Figure 32. ERCOT Industry Structure



1. ERCOT fulfills other NERC functions not indicated in this diagram
2. Potomac Economics serves as the current Independent Market Monitor for ERCOT.
3. The dotted lines connecting entities in the retail layer show the relations in the presence of an aggregator.
4. TSP approves or denies transmission service requests from purchasing-selling entities, generator owners and load-serving entities (not shown in diagram)
5. All market participants are monitored by Potomac Economics, and they have to be notified any changes in ownership and structure (not shown in diagram)
6. Wholesale storage load is part of the merchant generators.

Understanding such industry and market structures provides insight into sensing, communications, and data/information flow requirements (type, latency, and capacity bandwidth) and helps to formulate the rules by which the various participants will coordinate. These rules will need to specify requirements for both normal and contingent operations. Rules governing the relationship between the grid operator (e.g., utility or regional operator) and any facility (which may be owned by a customer or third party) are called grid codes; they define the technical specifications at the utility/facility interface associated with business/market terms and conditions, system operations under normal and emergency conditions, communication and control parameters, and the physical electrical interconnection.

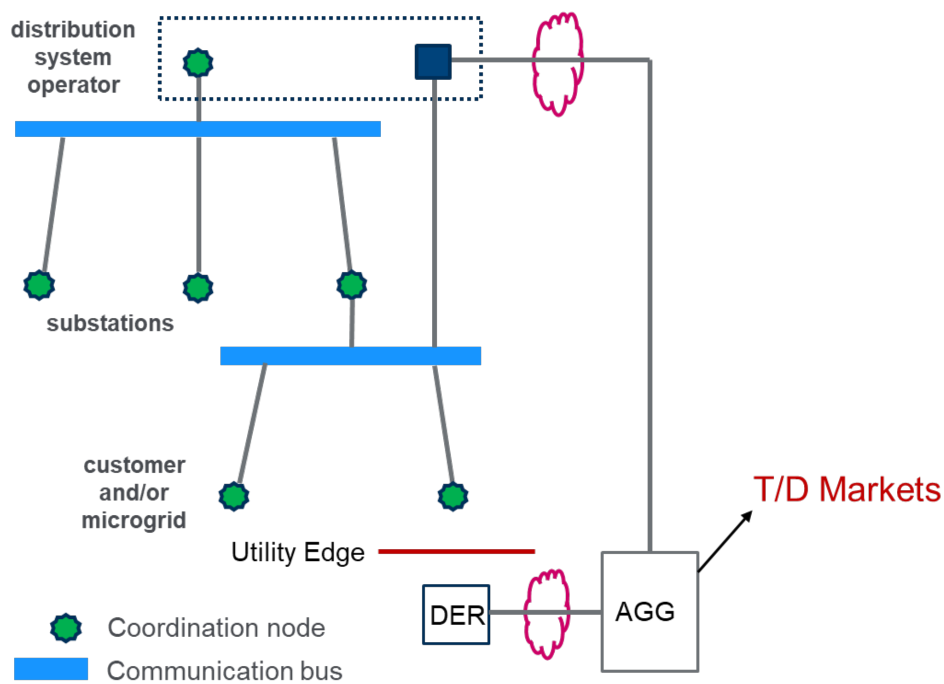
3.5.2.2 Scalability

Scalability is the ability of a system to accommodate an increasing number of endpoints without requiring major rework in system design. It also refers to the ability to roll out new infrastructure or investments in a proportional or incremental fashion, as needs may dictate (e.g., deploying new functions in portions of the utility service territory) while utilizing core infrastructure throughout. Therefore, system scalability has both spatial and temporal dimensions.

As the number of grid-edge devices and new participants that may own them continues to grow, the ability to scale proportionally, while maintaining effective grid operations, is becoming increasingly important. Each new DER, whether a photovoltaic system, energy storage device, electric vehicle, or flexible load (building or microgrid), will have inherent performance capabilities and constraints that will need to be factored into the active management of the grid. Grid operators, for instance, will need to know the effective state-of-charge of an energy storage device, as well as its recharge and discharge capability, at any given moment to effectively apply it as a grid asset. Furthermore, non-utility owners or operators of DERs may have specific goals, perhaps based on economic drivers, that may influence how or when they wish to operate their DER assets.

These objectives may differ from those of the utility at any given time or place (e.g., logistical issues associated with electric vehicle charging). As a result, scalability considerations include providing a capability to accommodate an increasing number of DERs in a way that recognizes both local (or selfish) interests and system-wide operational requirements—even over short timespans—and effectively balances the optimization objectives of both. Having hundreds, thousands, or millions of endpoints reporting to a single coordination node is not practical. As shown in **Figure 33**, the application of a laminar coordination framework that applies a layered structure is one approach for addressing the scaling and optimization problem as we increase the number of DERs on the system.

Figure 33. Three-Layered Idealized Coordination Framework



In above figure, an idealized coordination framework is depicted showing three layers, one representing the distribution system operator, another representing distribution substations, and the lowest layer representing customers (or even a microgrid, which would house additional sublayers). In this framework, each coordination node is responsible for optimizing operations beneath it; also, peer nodes coordinate within a layer, but are ultimately controlled by the node above them. Building out a grid in this layered, branching fashion enables the system to scale and permits nodes to optimize locally while respecting system requirements.

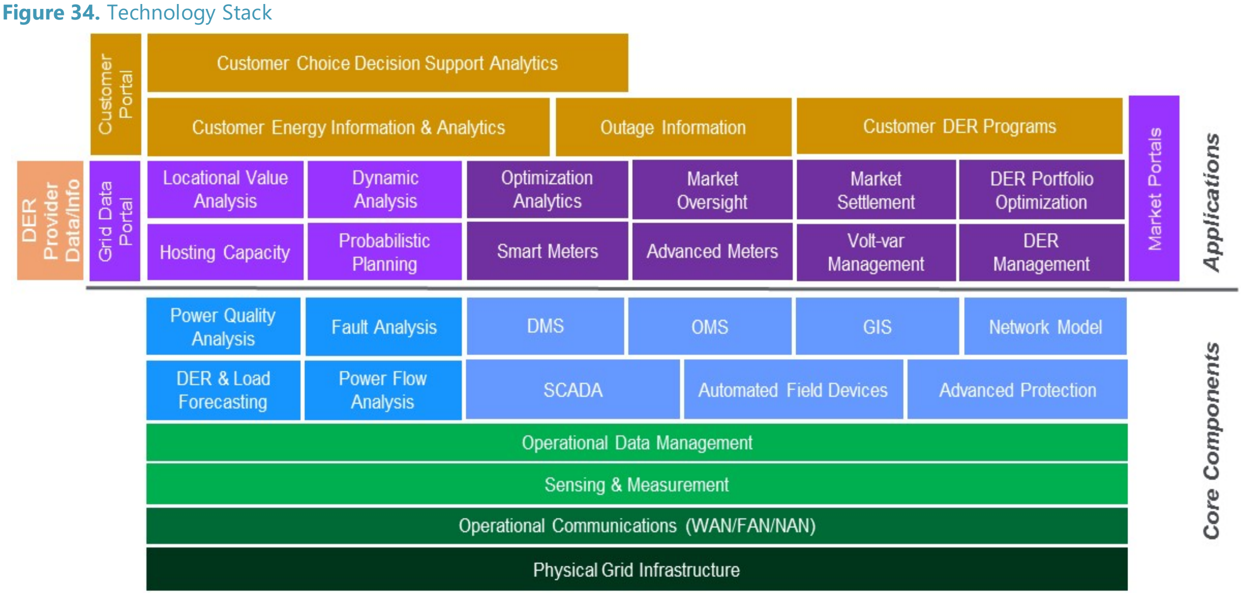
Note that the DER located at the bottom right of the figure is controlled by an aggregator although it is electrically connected to the grid. The coordination pathway depicted in the diagram permits the aggregator to control that DER while remaining within the operational regime dictated by its controlling node (just above it) so as not to violate system management requirements (e.g., voltage, frequency, power flow, and energy capacity needs). Minimizing the number of physical communication pathways between aggregators and the grid operator also reduces the potential for unwanted cyber intrusion.

3.5.2.3 Layering

Layering is the application of fundamental or commonly needed capabilities to support a variety of applications through well-defined interoperable surfaces. Layering for complex systems like the grid can also be used to simplify complex coordination challenges. One of the advantages of layered systems with at least three layers (as depicted in the previous figure) is that each layer can insulate the layer above—i.e., the intermediate layer(s) from changes in the layer below—and vice versa.[40]

Many utility systems are arranged in siloes, each vertically structured with its own sensors and networks and coupled through back-end data connectors. Siloes present significant system integration challenges and make it difficult to easily add new applications and functions. However, as shown in **Figure 34**, it becomes useful to identify core system components and treat them as a supporting layer or platform for a variety of applications that can be added over time. In this figure, the physical grid, communication networks, sensing and control functions, and data/information management systems are treated as core platform components supporting applications such as DER management, customer and market interactions, volt/VAR management, and advanced utility analytics.

Figure 34. Technology Stack



As discussed previously, it is important to consider the applications or functions needed over time to understand how to effectively build out the supporting platform. This modularization of a complex system like the distribution grid enables functions to evolve incrementally as needs dictate, consistent with the overall architecture.[41,42] Key properties of a platform include the ability to:

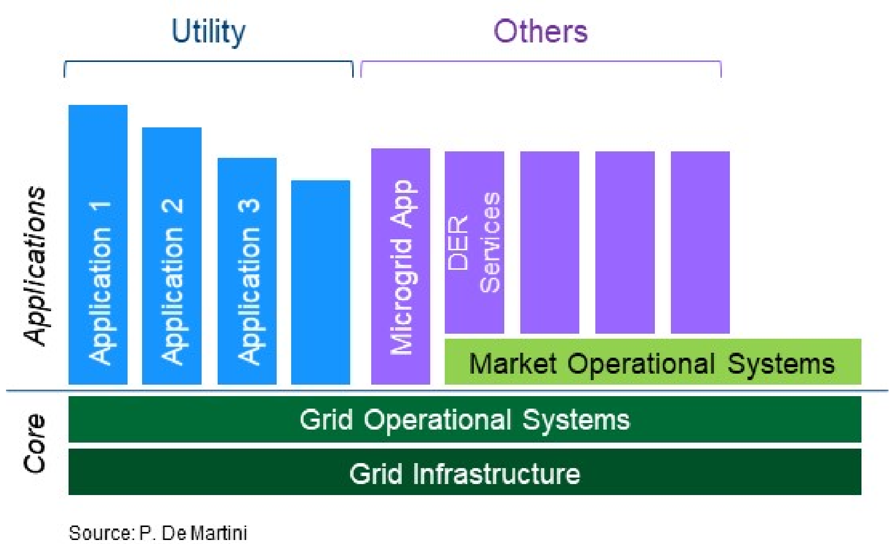
- Separate foundation functions from end uses ("applications") via layering

- Provide a set of services and capabilities that are useful to many applications (i.e., the platform is stable over time, while the applications may change frequently)
- Decouple changes between applications and underlying core infrastructure
- Scale (adjust resources) to support variable demands from applications
- Remain open, i.e., enable third parties to freely create applications that use the platform (which requires open standard interfaces)

Note that not every situation requires all this functionality or system-wide deployment of the core components. Each distribution system has a unique starting point, set of drivers for additional functionality, customer value, and policy considerations. Additionally, the specific technology choices within these categories, timing and pace of deployment, interdependencies of each, and the integration, interoperability and security of these components require careful consideration. In many cases, investments in several of these technologies have already begun, so a key consideration is how to continue further development as discussed in the conceptual roadmap in this chapter.

Another view of distribution grid platforms is that an effective architecture will allow third party applications to leverage aspects of the utility's core platform in addition to the utility's operational applications, as exemplified in a simple illustration of an open platform (**Figure 35**). A third-party microgrid operator may directly interface with the distribution system operator to coordinate operations during microgrid islanding and re-synchronization. A DER aggregator will often interface with utility-owned systems like a procurement portal and an operating system such as a distributed energy resources management system (DERMS) to enable dispatch of the aggregated resources.

Figure 35. Open Platform

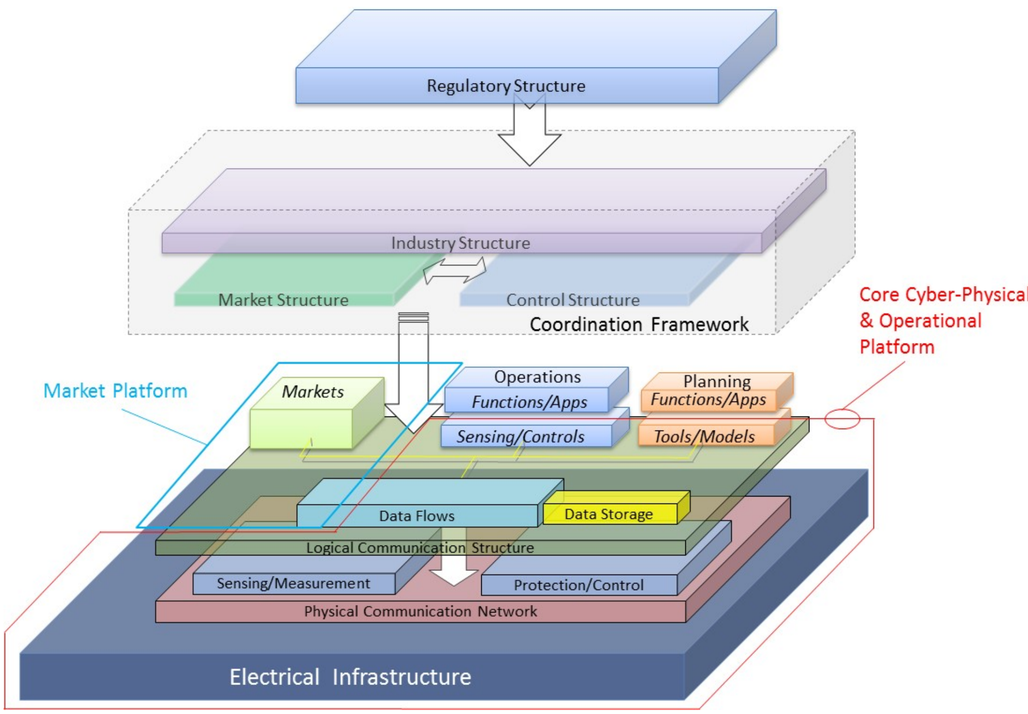


A modern distribution grid, as explored in this Guidebook, involves the development of a cyber-physical infrastructure platform, while other related modules enable the creation of a distribution operational market transaction platform (as shown above). The two platform types just described can be thought of incrementally. The cyber-physical grid platform must exist even if only to provide traditional electric service, and it must be modernized if higher DER presence is anticipated, irrespective of whether any given state jurisdiction decides to adopt a market or transactional platform. While complicated, the concept of platforms is important to understand in relation to the development of modernization plans and related technology investments. The use of the platform approach helps to organize, manage, and operate the complexity of organizing the diversity of elements needed in a modernized distribution system.

The platform concept is also important when one begins to consider the *convergence* of the electric grid with other infrastructures, as may happen in a city where the physical grid—as well as sensing, communication, and control functions—might be shared with other systems, such as building and transportation systems and emergency operations. The convergence of the electric grid and natural gas infrastructures should also be considered to achieve operational efficiency and resilience.

Figure 36 illustrates the interrelationship between cyber-physical infrastructure that comprise the core platform and the applications and the market platform that are dependent on the core platform. These in turn enable the market and control structures that, along with the industry structure, govern the operation of the electric system—also called the coordination framework.

Figure 36. Cyber-Physical Structure Interrelationships



3.5.2.4 Buffering

Buffering is the ability of the grid to withstand a variety of perturbations. Buffers are mechanisms for decoupling flow variations, especially random or unpredictable variations. The presence of a buffer provides a system with "springiness" or "sponginess" that makes it resilient to a variety of perturbations. In fact, the lack of such springiness is a resilience vulnerability. Most complex systems have some form of buffering. Communication systems have "jitter buffers" to even out the flow of data bits in communication network transmission. Computing systems have various kinds of data buffers that operate on differing time scales. Logistics systems have buffers (called warehouses), whereas water and gas systems' buffers are called storage tanks. In each case, the buffer is some form of storage that evens out irregular flows, thus reducing or eliminating the impact of volatility (fluctuation or interruption) in source or use.

Electric power grids have many systems that can benefit from buffering, including the whole grid infrastructure.[43] Increasing volatility in the grid power flows caused by addition of variable energy resources is increasing stress in grid operations and requiring greater system flexibility. The lack of fast, flexible buffering is a factor in the inherent lack of resilience of the grid. Increasing buffering capability is possible by adding some form of storage and using systems, such as grid-interactive buildings, to actively manage load in concert with grid operators. As the ability to adsorb stresses with little or no loss in performance is becoming a necessary grid characteristic, storage and flexible systems should be incorporated into the grid as core infrastructure and must be deeply integrated into grid operations.

These four key architectural considerations are interrelated and inform the development of the architectural strategies for the following key building blocks of a modern grid.

3.5.3 Strategic Architectural Considerations

Architectural strategies are plans that contain conceptual views derived from rigorous basic architectural principles and concepts as described above. These strategies will inform detailed designs of specific aspects of the grid. This section provides a set of considerations and guidelines to aid in the development of architectural strategies regarding:

- Grid structure and circuit topology
- Operational coordination frameworks
- Protection and control
- Observability
- Data management and analytics
- Operational communications
- Cyber-physical security

Developing such strategies requires knowledge of the specifics of a particular grid and the objectives for its modernization.

3.5.3.1 Grid Structure and Circuit Topology

The cyber infrastructure (i.e., the structure of sensing, communication, control, information management, and computing systems) is designed to manage the physical infrastructure. This requires a capability to monitor and control the physical hardware to support grid operations with respect to both spatial and temporal dimensions. For example, when grids are built with variable structure (i.e., can automatically change configuration to meet operational needs such as reducing the exposure of customers to outages), methods for determining and distributing information must operate within appropriate timeframes. Some situations may require that grid control operate in real time to effectively manage the as-operated structure.[xvii]

The scenarios[44] in **Figure 37** show configuration changes for a given set of circuits, highlighting the need to address dynamic structural situations. **Scenario A** shows normal distribution system operations with

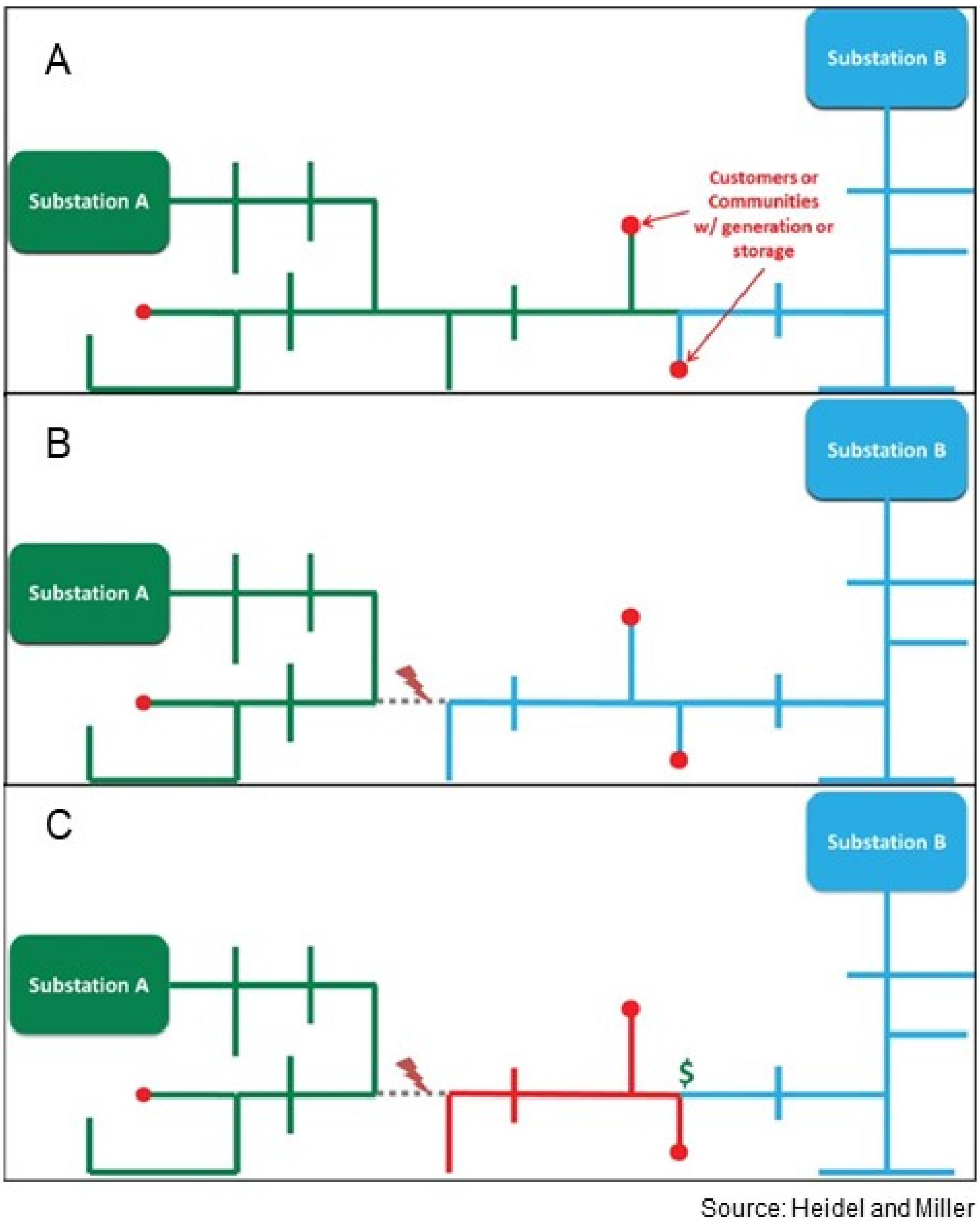
[xvii] The "as-operated" structure is the physical set of components being operated at any given time.

power fed from two substations: Substations A and B. The green and blue portions of the feeders are electrically isolated by a normally open switch.

Scenario B depicts a looped distribution system configuration, widely used today, which is capable of transferring some customers to a new substation feed in the case of an outage in a portion of the network to minimize the scale and duration of the outage.

Scenario C shows a grid design employing a microgrid subsystem which enables portions of the system (shown in red) to operate independently to satisfy objectives for reliability and economics. Decisions on when and how to segment networks can be made centrally or in a distributed fashion.

Figure 37. Grid Structural Scenarios



A traditional weakness of distribution operations is that the system model (especially as related to electrical connectivity) is not known with total accuracy. This is in large part due to distribution systems, by design, frequently changing their configuration, as described above. To avoid the problem of trying to adjust communications structure to track as-operated grid structure, the communications layer, serving as a platform, should be designed to support the total system comprising the electric hardware so as to accommodate changing configurations associated with the as-operated structure.

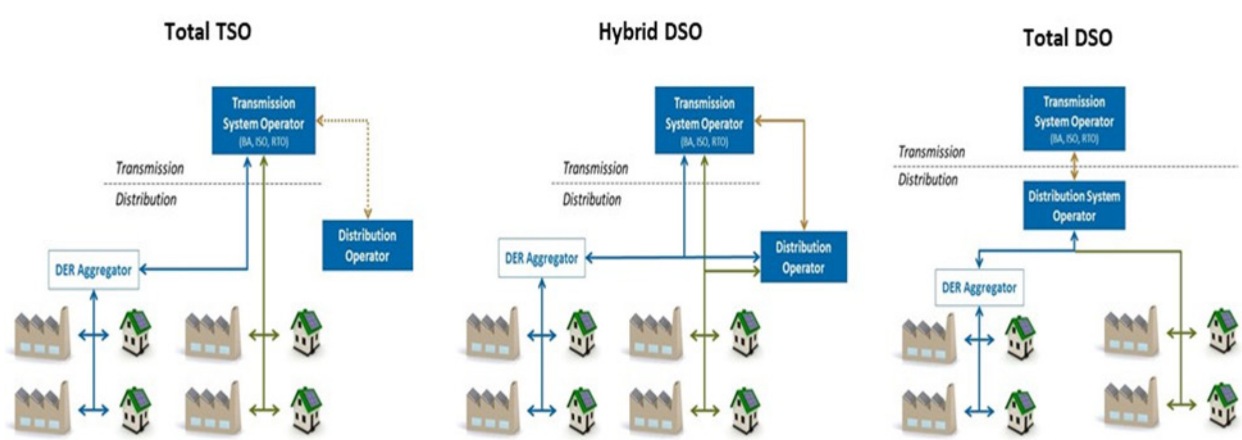
Gaining an understanding of grid topology and circuit reconfiguration as affected by the use of microgrids or other approaches for improving the reliability and resilience of the grid is important for designing appropriate supporting layers for sensing, communication, and control, as well as the coordination framework.

3.5.3.2 Operational Coordination Framework

As discussed previously, operational coordination includes a wide range of activities shared between all participants engaged in the generation, use, and management of electricity within a framework of specified roles, responsibilities, business processes, and technical requirements. This includes information exchange and control coordination of all participants in the provision of energy and grid services to maintain and contribute to reliable system operations. The transformational changes taking place will require new transmission-distribution-customer (TDC)[xviii] coordination frameworks to ensure reliable and effective grid systems.[45]

Figure 38 provides a simple conceptual TDC coordination skeletal diagram for three reference models: a total transmission system operator model (Total TSO), a hybrid operator model (Hybrid DSO), and a total distribution system operator model (Total DSO). Most coordination frameworks being considered today follow the hybrid model concept. These three models are offered to illustrate how various architectural considerations are needed to develop an effective coordination framework.

Figure 38. TDC Coordination Reference Models



In the Total TSO model, the transmission system operator (TSO) optimizes the entire power system and oversees the dispatch coordination of all DER services and schedules; the distribution system operator

[xviii] The term "transmission" used in this sense is meant to represent the bulk-power system, consisting of generating resources, transmission lines, and operating equipment.

(DSO) is responsible for reliable distribution network operations and providing distribution network visibility to the TSO.

In the Total DSO model, the TSO optimizes the bulk power system, while the DSO is responsible for the physical coordination and aggregation of all DER services into a single resource (offered to the TSO) at the T/D interface; this model adheres strictly to a laminar coordination framework approach. In the Hybrid DSO, the TSO optimizes the bulk power system while the DSO optimizes the distribution system, though customer/aggregator DERs can coordinate with both. Understanding how all resources are effectively coordinated within a grid is important as transmission-level markets open to DER participation exist and continue to evolve.

From an operational point of view, TDC coordination frameworks will need to address specific design issues. For example, such frameworks may need to coordinate significant levels of DERs participating in both wholesale and retail markets or operations, while doing so in a way that recognizes their respective performance characteristics within an acceptable range of grid operating conditions. The ability to manage DER effectively will require high levels of visibility into the distribution system and control under a variety of conditions. Any TDC coordination model will need to address:

- Tier bypassing—i.e., the creation of information flow or instruction/dispatch/control paths that skip around a tier (or layer) of the power system hierarchy, thus opening the possibility for creating operational problems, such as voltage excursions and power overloads at the distribution system level, if that layer is bypassed.
- Hidden coupling of operational controls—i.e., where two or more control systems with partial views of grid state (e.g., the TSO and DSO) may send conflicting signals to the same DER.
- Scalability of inherent operational processes and related technological designs; it may become impossible for a TSO to effectively coordinate a multitude of DERs, especially under constantly changing distribution grid conditions.
- Cybersecurity vulnerability from or through DER with unknown protection; minimizing communication and control channels to both TSO and DSO will reduce cybersecurity vulnerability.

The development of TDC coordination frameworks will require significant input from stakeholders representing various jurisdictional domains. Operational coordination issues are beginning to emerge and the determination of the respective roles and responsibilities of the various participants, including their data/information flow requirements, needs to be addressed.

3.5.3.3 Protection and Control

As described above, coordinating devices, systems, and entities in a modernized grid environment is a complex, multi-scale problem.

With the advent of DER, protection for modernized distribution grids must be designed to permit alternate two-way flow of real power at the circuit level. In addition, new devices attached to the grid—such as solar PV and storage inverters—pose new safety issues if their output is not appropriately controlled, especially under contingency circumstances. The possibility of the grid to change configuration, as described above, poses protection issues since the electrical connectivity and loading of a circuit protective device may change from moment to moment.

Grid management entails a number of control functions, as listed in **Figure 39**. As DER adoption increases and distribution grids move toward supporting a wide array of energy transactions, more of these control functions will apply at distribution system level.

Figure 39. Distribution Grid Control Function Classes

Control Function
Voltage Regulation
Reactive Power Regulation
Stabilization
Synchronization
Secondary Load Control
State of Charge Management
Grid Structure Control
Flow Control, including Power Wheeling

Grids structured in modular fashion, such as networks of microgrids (see Scenario C in Figure 37 on page 64), require a power wheeling control function[xix] normally thought of at only the bulk power level. Grids with variable structure need integrated grid structure control. Current examples of integrated control are undertaken by supervisory control and data acquisition (SCADA) systems and fault location, isolation, and service restoration (FLISR) systems, but these two systems are typically disjointed. For a grid supporting energy transactions, storage, and a variety of non-utility connected devices, dynamic grid structure control must be integrated into grid operations.

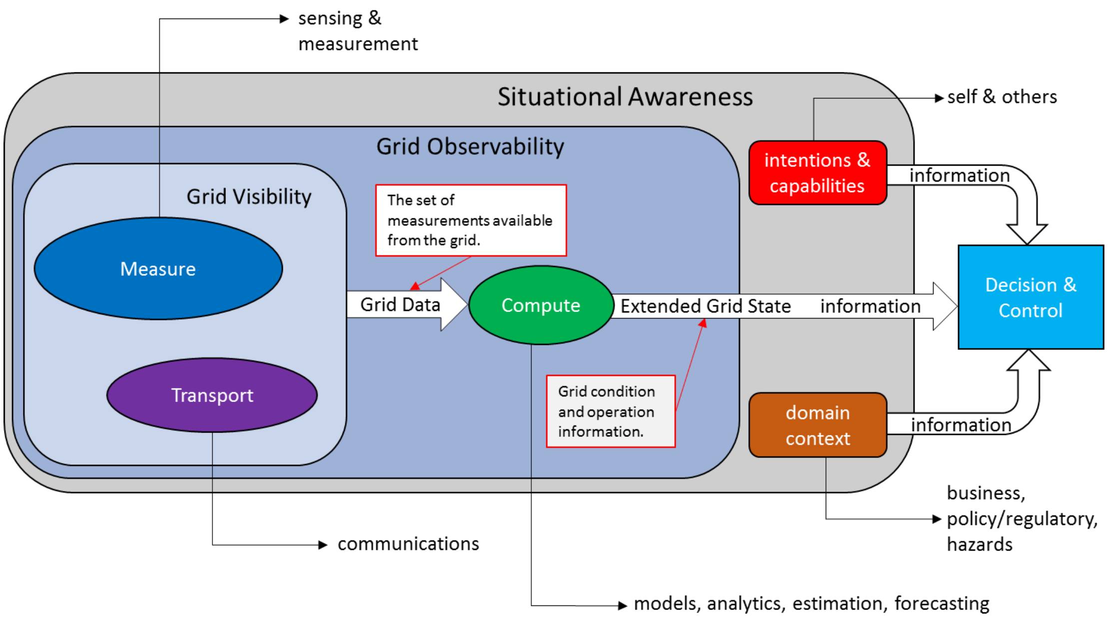
For grids with embedded storage as core infrastructure, management of the storage for resilience and flexibility and the subsequent control of state-of-charge are new control functions. In the past, grid control has mainly been about control of power state and volt/Var regulation. With the advent of embedded energy storage, the state of charge of a storage system will be another element to monitor and control.

3.5.3.4 Observability

To operate a modern grid, it is necessary to have certain information (observability) about the grid and its real-time operations. Observability is the combination of directly measured parameters (visibility) and what can be determined from the measurements using a system model (situational awareness). As defined in Volume I, situational awareness involves operational visibility into physical variables (from grid assets, including DER), events, and forecasting for all grid conditions that may need to be addressed, including for normal and contingent operation states, criteria violations, equipment failures, customer outages, and cybersecurity events.[46] Situational awareness is also required to reliably operate a grid with a high penetration of DER while also optimizing DER provided services. This includes visibility of the operation of interconnected DERs. These characteristics and their structural relationships are illustrated in **Figure 40**.

[xix] Wheeling is the transportation of electric energy from within (or through) an electric grid to a load outside the electric grid boundaries.

Figure 40. Observability Definitions and Relationships



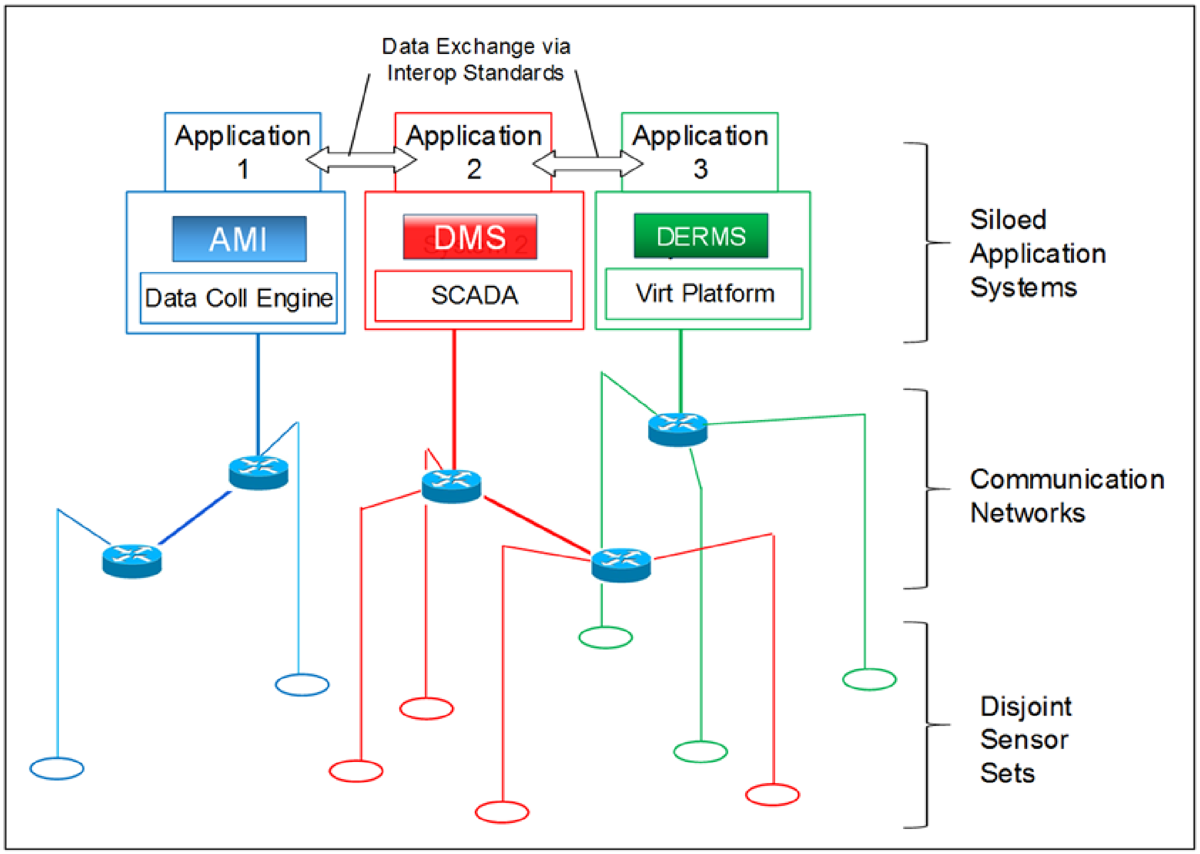
An observability strategy is needed for the development of a grid modernization strategy and is also a prerequisite for designs and implementation plans as a way to ensure appropriate situational awareness can be effectively achieved. An effective observability strategy will include a sensor allocation methodology for the grid to avoid the need for massive amounts of sensing. Such a strategy determines the types, amounts, and locations of sensors based on the need to have a given amount of observability to support the required grid functions and applications.

As distribution grid functionality changes, the dynamics of the grid are becoming increasingly faster and the delivery of data from source to use is therefore critical. Requirements for bandwidth, latency, and packet loss[xx] are becoming more stringent as distribution grids support increasingly sophisticated functions and connected non-utility active devices.

One additional challenge that should be addressed in architecture strategies is legacy structural constraints regarding sensing and measurement, communications, and operational systems. Distribution systems based on proprietary vendor products have historically been designed in a siloed fashion so that each application system has its own sensing and may have its own communication system, as illustrated in **Figure 41**. This multiple vertical silo structure is expensive due to back-end integration costs and is anti-resilient due to the back end coupling of applications—failure in one can ripple through to degrade others. It is also anti-extensible because adding or subtracting applications requires new integration to existing applications.

[xx] Packet loss occurs when one or more packets of data travelling across a computer network fail to reach their destination.

Figure 41. Siloed Applications

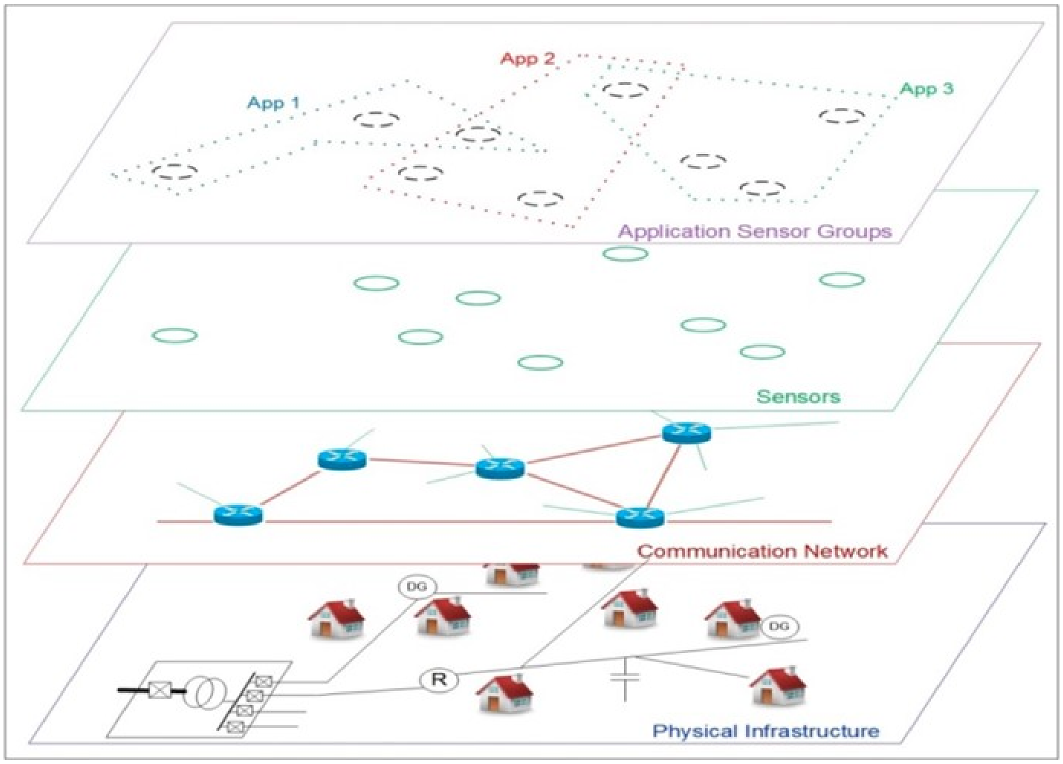


As introduced above, sensing and operational field communications for grid management and coordination can be structured as a layer of a multi-layer platform that includes the underlying electric infrastructure. Sensors can then stream data and the network can act as a publish/subscribe mechanism[xxi] for any authorized application, whether it is distributed or centralized, or even cloud-based (**Figure 42**).

In practice, achieving this desirable structure is quite difficult given vendor resistance to enabling product architectures and interoperable interfaces. This is akin to the relatively open Microsoft personal computing and software platform versus Apple's relatively closed hardware and software systems. The utility industry, EPRI, NIST, and DOE have pursued several initiatives over the past 20 years to advance these concepts into commercial products.

[xxi] In software architecture, publish–subscribe is a messaging approach where senders of messages (publishers) do not program the messages to be sent directly to specific receivers (subscribers), but instead categorize published messages into classes without knowledge of which subscribers, if any, there may be.

Figure 42. Physical Grid, Communications, Sensor and Operational Application Layers



The observability strategy should first consider any sensing already present and then determine how much more is needed to achieve the necessary visibility and situational awareness. Two types of optimization strategies are relevant here:

1. Maximize the amount of observability for a fixed sensor budget
2. Minimize the cost to achieve a fixed amount of observability

Either approach may be used, depending on specifics of the particular grid and grid modernization plan.

As grids increase in sophistication, timing and synchronization become more critical, and the need for synchronized measurement at the distribution system arises. The sensor and application system must be capable of receiving timing signals through the communications network.

3.5.3.5 Data Management and Analytics

"Big data" and analytics discussions often do not differentiate between the several types of data found in utility operations or the temporal aspects related to data transfer needs. It is important to distinguish different types of data such as the operational state of devices and grid components as well as their performance characteristics; electric network contextual information; market participant/customer data; geospatial information; and dispatchability of grid resources (see **Figure 43** for additional data types). To manage data effectively, it is essential to understand the differences between each data class, their potential applications, and their respective exchange (latency) considerations. Framing the data characteristics correctly allows proper treatment and identification of effective management solutions.

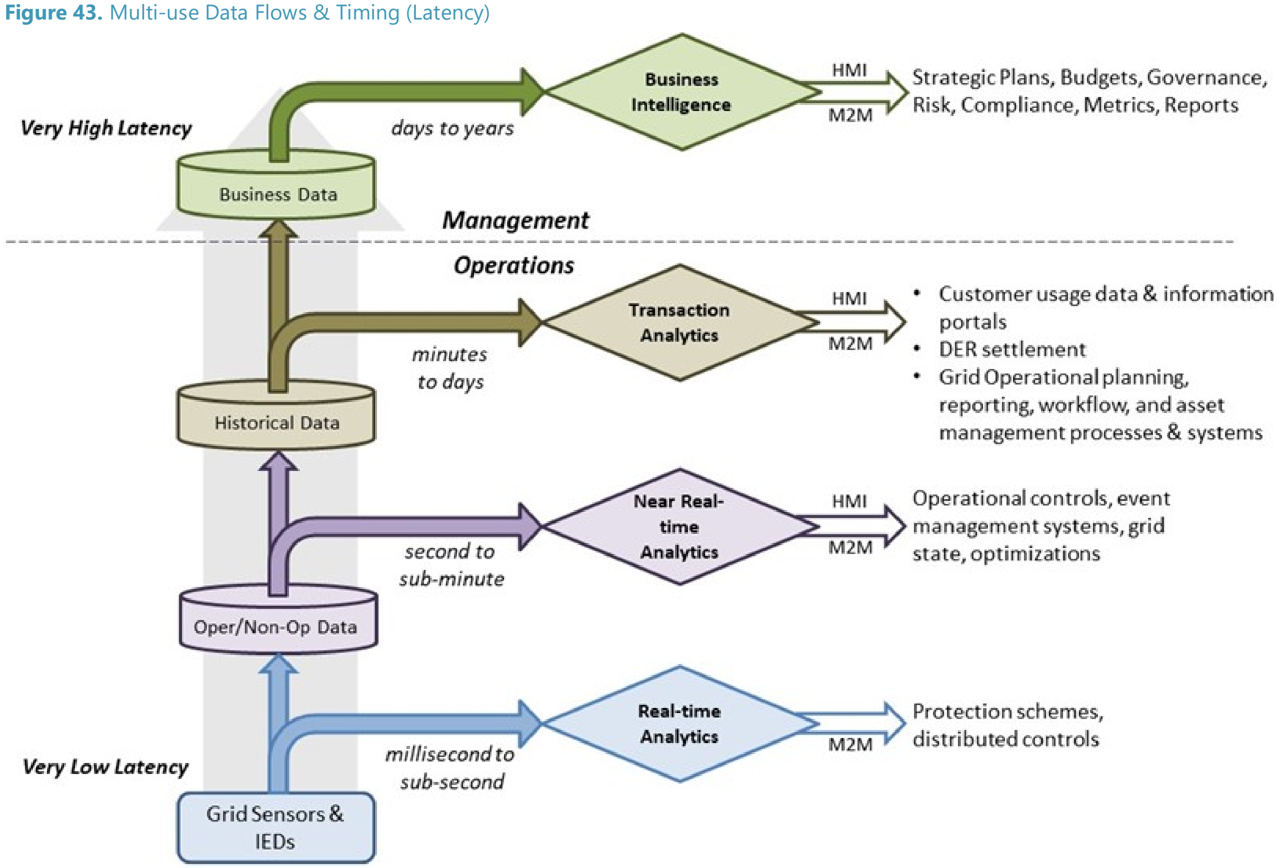
Much of the industry discussion today on data management solutions seems to ignore this initial step in understanding the nature of the architectural and engineering problems to solve, causing potential challenges when integrating into the unified energy platform. Further, without a clear understanding of the potential analytics and business use from developing a data and analytic architecture at the outset, utilities risk creating stranded costs from having to rework data stores and possibly buying the wrong data management solutions.

For distributed analytics and data management, the logical flow of data may have to change as the variable structure of the grid changes. For instance, if a feeder section can be switched between two different substations and the analytics are done at the substation level, then the data management software must be capable of tracking the grid as-operated structure and making the appropriate adjustments.

Identifying the temporal aspects of the underlying business processes and control systems is a critical consideration to develop effective data management strategies and architectures. A lot of grid data has multiple uses; it is important when considering economic and system design efficiencies to ensure that data is used to support as many outcomes as possible, as well as to understand the implications of the growth in grid sensor and control data streams.

An important factor for data management is the timing (latency) for both the time interval between the time that data is requested by the system and the time the data is provided by a source, and/or the time that elapses between an event and the response to it (**Figure 43**). This why it is important to understand how data is consumed in a variety of ways and places in a power grid and in utility operations. [47]

Figure 43. Multi-use Data Flows & Timing (Latency)



As discussed above, an architectural view of a sensor network, shown in **Figure 44**, treats grid sensors and the utility communication network as an integrated structure layer. In this structure, data can flow from sensors in continual streams to any authorized recipient application. In fact, multiple devices or applications can receive such streams from the same sensor—applications merely need to be connected to the network at some point. This can be referred to as "plug and play." In this sense, the sensor network can operate as a publish-and-subscribe data system supporting multiple uses, each with distinct timing and performance requirements.

Figure 44. Layered Sensor, Communications, and Application Structure

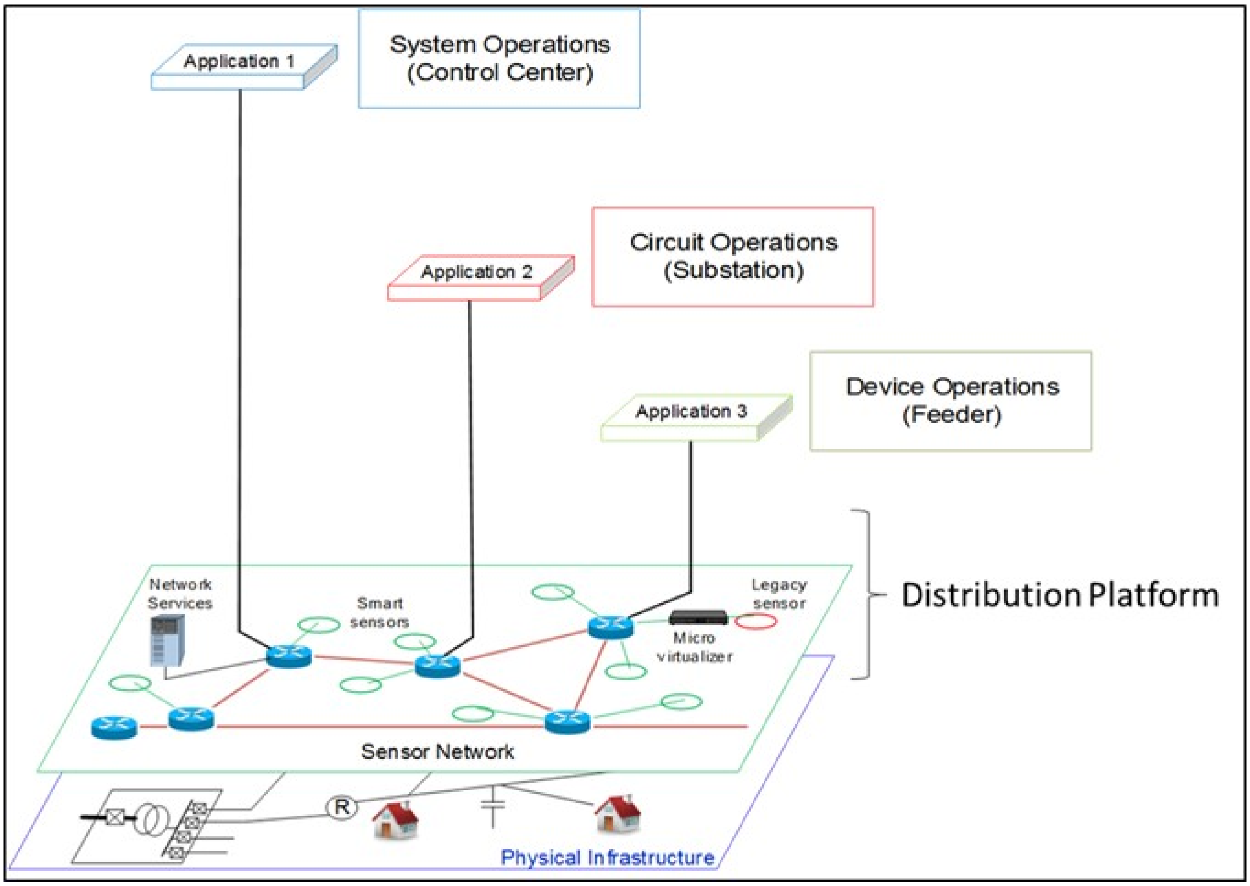
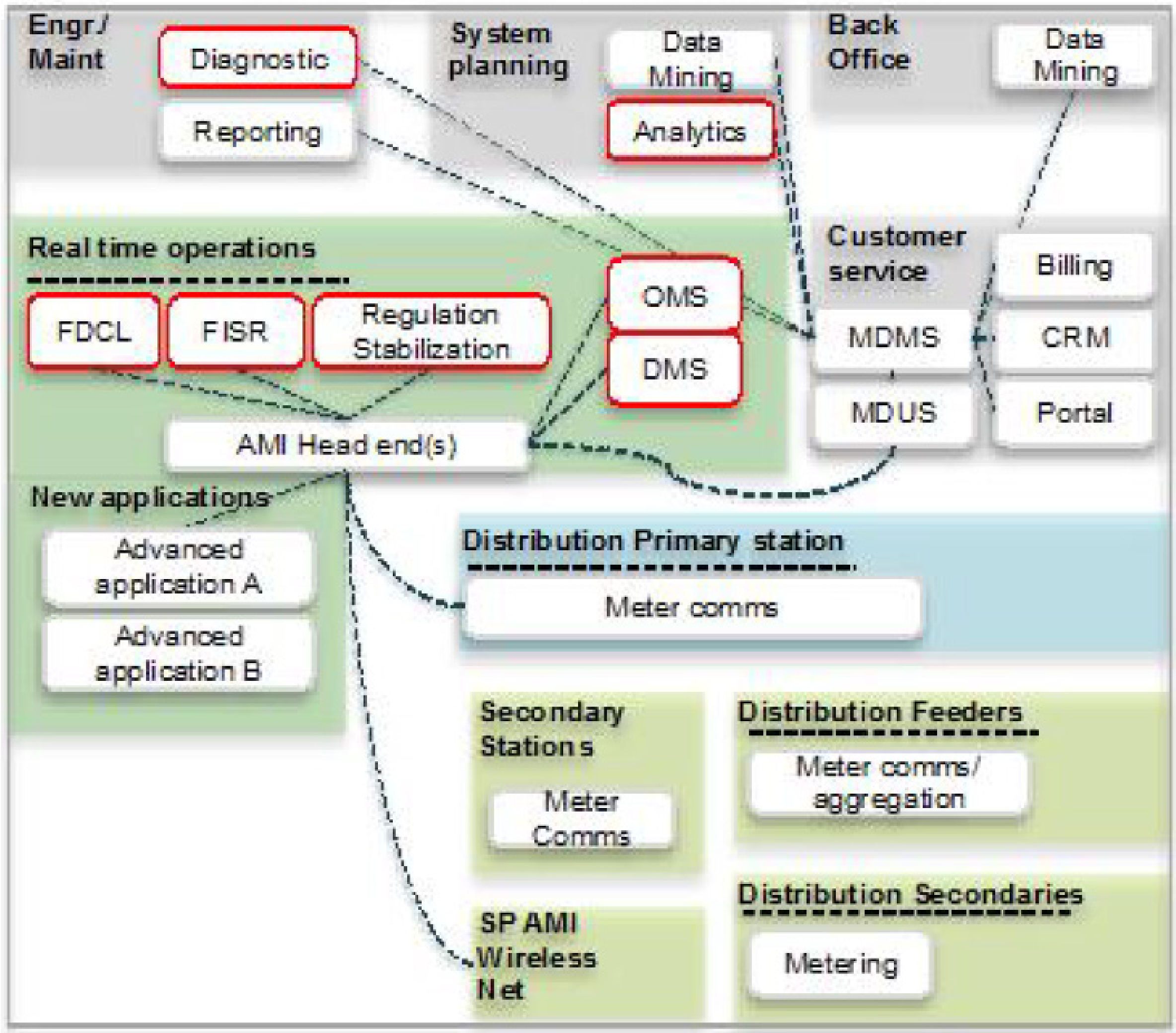


Figure 45 illustrates how data from an AMI system may be used to support multiple operational process and analysis. Each use has unique performance and latency requirements. Smart meters can serve as sensors providing data to multiple applications.

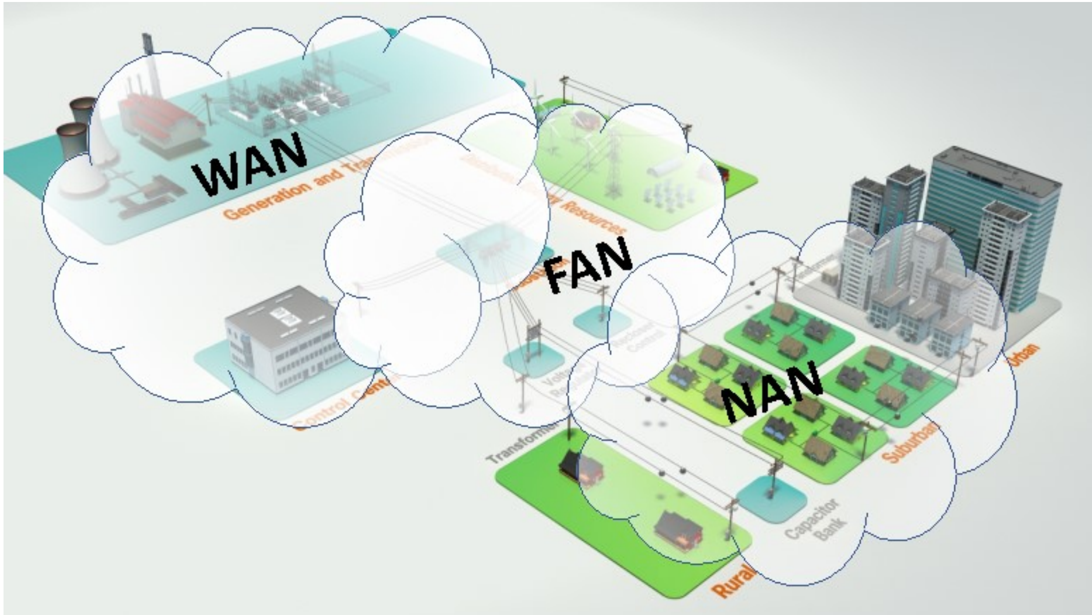
Figure 45. Multiple Uses of AMI Data



3.5.3.6 Operational Communications

Operational communication networks involve the integration of multiple physical communication networks that may include both private infrastructure as well as telecommunication service provider (TSP) infrastructure. An operational communication network can be grouped into a hierarchical system of three general parts ("tiers"): wide area network (WAN), field area network (FAN), and neighborhood area network (NAN) with functions illustrated in **Figure 46**.

Figure 46. Illustration of Operational Communication Network Tiers



Each tier offers services that can be tailored to specific requirements of systems, devices, and applications such as bandwidth, latency, resilience, and security. Each tier also employs multiple types of communication infrastructure or media such as optical fiber, wireline, or one or more of the many wireless radio technologies available within existing infrastructure or suitable to specific locations and requirements.[48]

Relative to other investments in grid modernization, operational communication networks, like the physical grid, represent a fundamental enabling technology required by all the capabilities described in Volume I. Proper architecture, design, and implementation will also lower the incremental cost of adding capabilities as required.

Operational communications architecture strategy development involves:

1. Identifying network requirements, including bandwidth ad latency considerations
2. Matching requirements against proven architectures and using relevant aspects of proven architectures as a starting point to inform the approach to development of an architecture
3. Developing a conceptual architecture network structure that addresses not only initial implementation, but also lifecycle management of the system

Operational communication networks for modern distribution grids have essential architectural and design considerations in several key areas. The starting point in developing an operational communications architecture is to identify customer and policy objectives as well as infrastructure considerations over its anticipated lifecycle (e.g., 15 years or more). This includes the related attributes that drive functional requirements to support substation and distribution automation, grid sensors, protection schemes, distributed device control, smart metering, DER integration and control, and other coordination requirements, as described above.

It is also necessary to consider the connectivity required to obtain system data (e.g., sensor/measurement information, event alerts, device status), send control signals to grid devices, and obtain any other information needed to manage and secure a communication network.[49] A grid communications network needs to enable an interoperable publish-and-subscribe schema to enable streaming operational data to the various systems that need the same data but may have different latency requirements, as discussed earlier.

A major benefit of an architectural approach to distribution grid modernization is the ability to place individual projects into context. For example, communications requirements for multiple applications overlap such that the additional marginal cost for a multi-services network may be more than offset by sharing the operational communication network service across multiple projects and applications. The deployment of that communications network may result in an optimized use of a core infrastructure that has lower overall costs to implement and maintain than the costs to build multiple siloed networks.

Both legacy SCADA and more distributed data collection can coexist on the same network. Each application may subscribe to individual sensors or devices as needed, providing low-latency data/control transport with great flexibility. This type of schema requires standards-based network management and security functions, as well as grid-specific capabilities such as sensor meta-data management, IEC 61850 CIM interface services,[50] and grid topology/connectivity requirements.

Conversely, an example of inefficient communications would be a voltage control application that accesses a smart meter in a traditional silo network structure, sends a request to a meter-data head-end system,[xxii] waits for the head end to query the meter via an AMI communications network, and waits until the head end provides a value back to the voltage control application via an enterprise wide area network. This type of scheme was prevalent in 2000's era single-purpose network configurations and is no longer preferred.

3.5.3.7 Cyber-Physical Security

A wide array of technical measures and processes have been developed to implement both cyber and physical security for electric power systems; information on these is widely available. What is less well known is that system vulnerability and security depend on the actual structure of the grid networks (e.g., electric, control and communications systems). During the design phase, these structures should be examined from the standpoint of structural vulnerability to cyber threats, not just vulnerability of individual devices. Cybersecurity strategy must account for the connection of non-utility devices such as DERs[51] and the communication paths that may exist not just into the utility systems, but elsewhere as well.

The DOE Office of Cybersecurity, Energy Security, and Emergency Response (CESER) and industry partners developed the Electricity Subsector Cybersecurity Capability Maturity Model (C2M2) to help private sector owners and operators better evaluate their cybersecurity capabilities. CESER's Energy Sector Cybersecurity Framework Implementation Guidance[52] discusses in detail how the C2M2 maps to the voluntary Cybersecurity Framework, as well as guidance to establish or align existing cybersecurity risk management programs to meet the objectives of NIST's Cybersecurity Framework.[53]

[xxii] A head-end system may consist of software and hardware that initiates and receives data from devices and may perform a limited amount of data validation before either making the data available for other systems.

3.5.4 Development of a Holistic Grid Architecture

Grids are complex; developing a grid architecture is a nontrivial task, especially as a system design is needed to accommodate numerous DERs and new grid configurations (e.g., microgrids). Grid architecture may be best developed by a small core team of architects experienced in the methods of system and grid architecture, backed up by subject matter experts.[xxiii] This work can be done by an electric utility entity or consortium of entities, depending on the scale of the modernization being done. In the case of DER integration, it may be necessary to involve multiple distribution utilities and a system operator, whereas if a single utility is pursuing a modernization strategy, it may perform the grid architecture work itself.

Regardless of system design options, the regulator must be able to comprehend the implications of the architecture. Some of the questions the regulator may want to ask of the utility include:

- What core architectural considerations have been applied?
- What architectural strategies have been developed, how were they selected, and over what timeframe?
- How were the architectural strategies and the overall architecture validated?
- How do the architectural decisions support the original modernization objectives and functional requirements?

It should be possible for the utility to demonstrate that the architectural decisions trace back to original requirements and sound architecture principles, just as engineering designs trace back to engineering requirements and associated design principles. As more detailed engineering designs are designed, the utility should be able to show how they comply with the strategies and constraints imposed by the architecture.

3.6 Strategic Roadmap

A grid modernization strategic roadmap synthesizes the analysis in the preceding steps into a strategic plan that defines desired outcomes and includes the major steps or milestones needed to advance the capabilities of the system from its current state. It serves as a communication tool to articulate the strategic rationale (the "why") and the high-level plan for getting there. This strategic roadmap will often span 5–10 years and be informed by a long-term integrated distribution plan and organizational strategic business plans.[54]

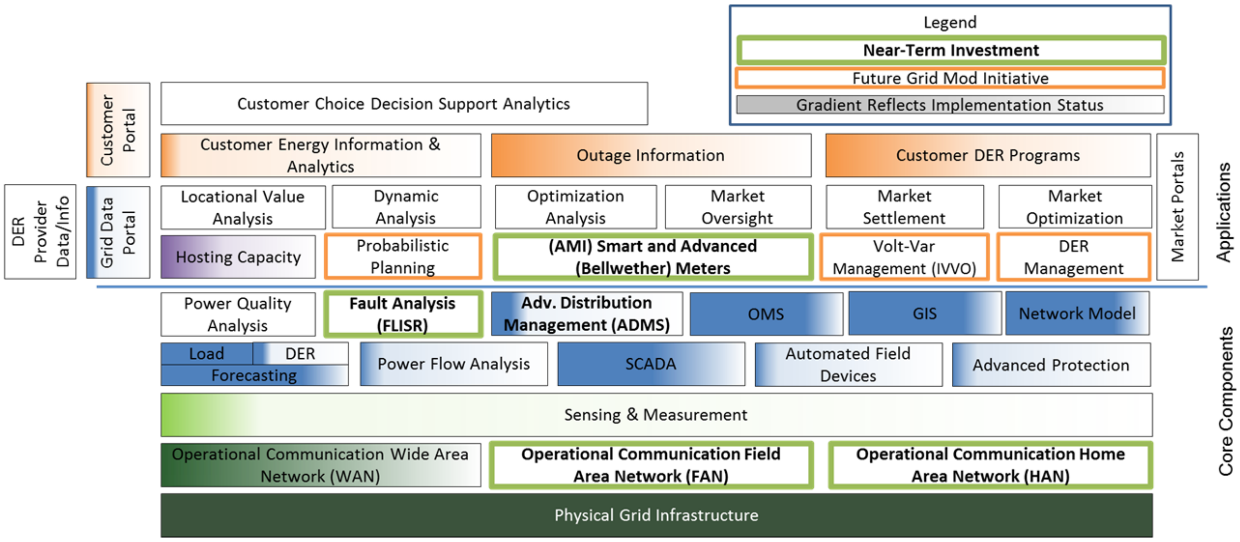
The starting point for developing a roadmap is understanding the functional capabilities and structure of the current distribution system. This sets the context for any changes or additions that may be required and is a recommended precursor to active engagement with stakeholders regarding grid modernization planning. Grid modernization may occur in a discrete proceeding or, as is the case in several states, occur as part of a larger IDP proceeding. Regardless, the strategic planning and roadmap steps discussed in this Guidebook are the same.

Figure 47 below is an example of Xcel Energy's illustration of their current status of grid modernization implementation and other planned investments in Minnesota[55] that leverages the DSPx platform

[xxiii] The discipline of grid architecture as described within this guidebook is fairly new, although tutorials and reference materials are available at the PNNL Grid Architecture website: https://gridarchitecture.pnnl.gov/.

framework from Volume III. The shading in the figure corresponds with the approximate level of technology deployment for the respective category. For example, the shaded SCADA box suggests that about 75 percent of the distribution substations have SCADA, and the network model is nearly complete.

Figure 47. Xcel Energy Grid Modernization Progress Status



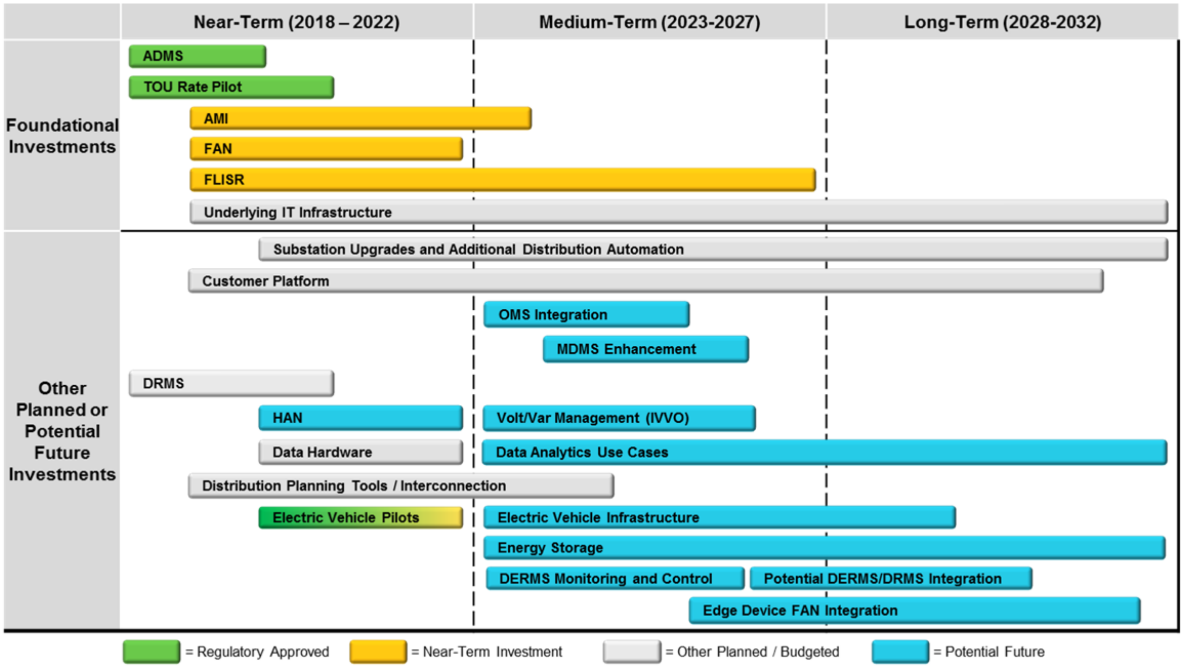
As described in this Guidebook, the grid modernization objectives create the reference point for what is needed over a defined time period. This includes enhancements to existing functions/technology and/or new functionality ("to address gaps") and technology investments needed over time. The rate at which the system advancements can be deployed should be specified in the IDP and may be dependent upon needed structural changes, the time it takes to assess and deploy technology, and budget constraints.

At this stage of developing a grid modernization strategy, the planning process should determine functional and structural requirements needed over time as well as identify the prerequisite, high-level requirements for related technologies. Technology discussions at this level are not vendor specific, but rather involve identification of technology categories that may be required. For example, ADMS is a technology category that incorporates a number of optional functional modules (e.g., DMS, OMS, SCADA, Network Model) that may be provided by a number of vendors. The strategic roadmap will identify the requisite technology categories in a logical relationship to specific objectives and related functionality. This line-of-sight reasoning is the foundation of the DSPx taxonomy and provides the basis for determining grid modernization planning alignment with customer need and policies.

A strategic roadmap will also combine the functional gap assessment with architectural analyses and a technology maturity assessment (see Chapter 4) to determine a conceptual deployment sequence. Several grid modernization technologies are at a pre-commercial or early stage of commercial availability, as discussed in depth in Volume II. Commercial availability is often described as commercial off the shelf (COTS), meaning it is readily available and can be integrated and used without much effort. However, the maturity of a technology needs to be factored into the time it may take to enable a specific function, as further testing and demonstration may be required.

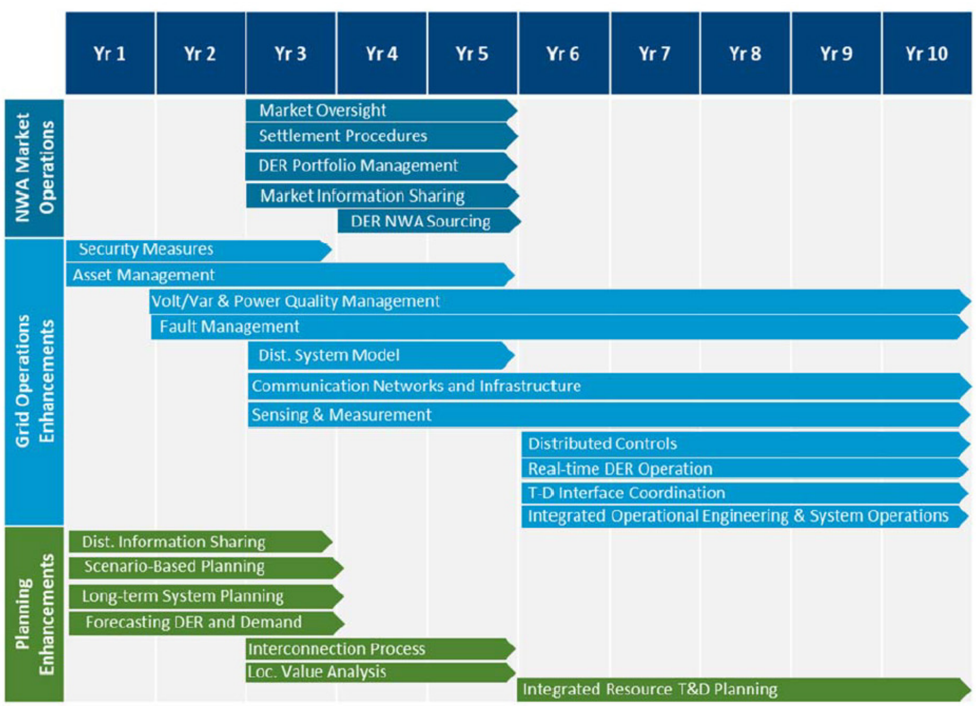
An example of a grid modernization roadmap from Xcel Energy is provided in **Figure 48** below. This roadmap provides the sequencing and timing dimensions to the technologies highlighted in Figure 47 above and adds a funding dimension to communicate both planned investments and whether/when funding is needed.

Figure 48. Xcel Energy 15-year Grid Modernization Roadmap



Similar to the technology conceptual roadmap described above, **Figure 49** shows New Hampshire's conceptual functionality roadmap as proposed by the Staff Report and Recommendation of Grid Modernization.[56]

Figure 49. NH PSC Staff's Proposed Conceptual Functional Roadmap



Strategic roadmaps like the one above often include a supporting conceptual cost estimate developed to enable planners to shape the timing and level of investment to align customer value along with grid needs identified in IDP.[xxiv] Conceptual cost estimates provide planners a basis to evaluate the investment feasibility in the strategic planning phase. These estimates do not reflect the detailed design and business impact assessment, nor the technology procurements, that are needed to inform the bottom-up engineering estimates are part of Implementation Planning (as discussed in Chapter 4).

Conceptual cost estimates are typically developed through one or more of the following top-down methods employed across industry sectors and governmental cost engineering practices:

- Historical estimating
- Parametric estimating
- Equipment-factored estimating

Historical estimating uses historical data from similar projects as a basis for the cost estimate. The estimate can be adjusted for known differences between the projects. In the electric industry, this type of estimate is effective if there are significant historical cost data on electric infrastructure to draw upon. This estimating technique is not effective for new technologies that have no historical implementation information.

Parametric estimating uses statistical modeling to develop a cost estimate. This technique uses historical data of key cost drivers to calculate an estimate for different parameters such as cost and scale as applied to the deployment of devices or systems. Square footage is one type of parametric estimate used in some construction projects. This type of estimating can be used for grid infrastructure and large-scale device deployments, such as smart meters where internal or external historical data is available. Conceptual cost estimates for full smart meter deployment can be developed using publicly available historical costs from similar sized utilities with similar geographic/seasonal weather conditions. This approach can yield an average cost per meter installed based on an average of reference total program costs for each peer utility divided by their number of meters installed.

Useful reference information for parametric estimates can often be found in relevant utility filings. An example of the type of information available is AEP's Indiana-Michigan Power Company (IMPC) subsidiary's filing[57] with the Michigan PSC. An excerpt from the recent 5-year distribution plan's Appendix 1 in **Figure 50** below highlights some of the planned grid modernization investments and related costs. The total cost for each technology (e.g., "smart recloser") can be divided by the total number installed to derive an average cost that may be useful as a reference if a similar type of smart recloser in comparable conditions is being considered as part of a conceptual estimate.

[xxiv] Customer value relates to the combination of tangible and intangible benefits a utility customer may experience as a result of obtaining electric service and options for managing energy.

Figure 50. IMPC 2019-2023 Grid Modernization Investment Plan Excerpt

Distribution Automation 2022				
Lakeside / New Buffalo	Union Pier / Bison	Install new automatic transfer scheme	1	Each
Main St / Riverside	Sears / Paw Paw Ave	Install new automatic transfer scheme	1	Each
		Total	2	
	Estimated O&M			
	Estimated Capital	$2,255,608		

Station SCADA 2020				
Station	Station	Description	Units	UOM
Stevensville	Stevensville	Install station SCADA	1	Each
Three Oaks	Three Oaks	Install station SCADA	1	Each
		Total	2	
	Estimated O&M			
	Estimated Capital	$2,393,443		

Station SCADA 2021				
Station	Station	Description	Units	UOM
Buchanan Hydro	Buchanan Hydro	Install station SCADA	1	Each
		Total	1	
	Estimated O&M			
	Estimated Capital	$1,175,727		

Smart Recloser Replacement 2019			
Station	Circuit	Description	Units
Colby	West 12 Kv	CA0227000562 Replace 3-400 VXE15	3
Colby	West 12 Kv	CA0227000563 Replace 3-400 VXE15	3
Covert	12 Kv	VB0301000024 Replace 3-400 VXE15	3
Crystal	Mercy Hospital 12 Kv	BE0218000200 Replace 3-400 VXE15	3
Crystal	Mercy Hospital 12 Kv	BE0218000960 Replace 3-400 VXE15	3
Hawthorne	Shoreham 12 Kv	BE0229000062 Replace 3-400 VXE15	3
Hawthorne	Shoreham 12 Kv	BE0245000007 Replace 3-400 VXE15	3
Lakeside	New Troy 12 Kv	BE0463000262 Replace 3-400 VXE15	3
Lakeside	New Troy 12 Kv	BE0532000060 Replace 3-400 VXE15	3
New Buffalo	Bison 12 Kv	BE0632000329 Replace 3-400 VXE15	3
Niles	East 12 Kv	BE0602000083 Replace 3-400 VXE15	3
Pigeon River	Elkhart Street 12 Kv	SJ0564000037 Replace 3-400 VXE15	3
Pigeon River	Elkhart Street 12 Kv	SJ0564000075 Replace 3-400 VXE15	3
Florence	Race Bank	SJ0465000285 Replace 3-100 V4L	3
Florence	Industrial Park	SJ0490000189 Replace 3-200 V4L	3
West Street	Paw Paw	BE0124000152 Replace 3 - 140 L (1A,2D)	3
		Total	48
	Estimated O&M	$1,089	
	Estimated Capital	$682,768	

Equipment-factored estimating is often accomplished by taking the indicative/list price of significant technology and/or equipment and multiplying it by installation and/or integration factors to arrive at the conceptual costs. The installation factor, or total installed cost, includes technology/equipment vendor and consulting costs, associated internal project labor costs, any additional costs needed for technology/equipment installation, and any ongoing operational and maintenance services costs. This has been proven useful since a substantial part of total grid modernization project costs are made up of technology/equipment. Typically, indicative pricing from technology/equipment vendors is used to estimate the price. The installation factor is developed from similar types of projects; for example, if equipment requires pole mounting, the cost to install a device with a similar size/complexity on a utility pole can provide a basis for estimation. Similarly, the implementation of software systems that have similar scope, interfaces, and configuration complexity can be used as estimating references.

Conceptual estimates developed using these top-down methods may include range estimates, as shown in **Figure 51**.

Figure 51. SCE Grid Modernization Conceptual Estimates

Category	Specific Investments		2015	2016	2017	2018 GRC (2018-2020)
Distribution Automation	#1	Automated Switches w/ Enhanced Telemetry	$500K - $1M	$3 - $5M	$35 - $60M	$185 - $320M
	#2	Remote Fault Indicators				
Substation Automation	#3	Substation Automation	$1.3 - $1.6M	$5 - $10M	$25 - $45M	$185 - $320M
	#4	Modern Protection Relays				
Communication Systems	#5	Field Area Network	$100 - $200K	$2 - $5M	$5 - $10M	$270 - $470M
	#6	Fiber Optic Network				
Technology Platforms and Applications	#7	Grid Analytics Platform	$10 - $13M	$65 - $100M	$55 - $85M	$215 - $375M
	#8	Grid Analytics Applications				
	#9	Long-Term Planning Tool Set				
	#10	Distribution Circuit Modeling Tool				
	#11	Generation Interconnection Application Processing Tool				
	#12	DRP Data Sharing Portal				
	#13	Grid and DER Management System				
	#14	Systems Architecture & Cybersecurity				
	#15	Distribution Volt/VAR Optimization				

Source: Southern California Edison

Conceptual estimates do not have the detail of an implementation plan or full-cost recovery request. However, these estimates can be useful to assess the magnitude of revenue requirements and associate rate impacts in consideration of customer affordability. Grid modernization strategies and related conceptual estimates have thus been employed in several states to facilitate a discussion among regulators, utilities, customers, and stakeholders regarding the pace and magnitude of technology investment that may be desired.

The objective of a conceptual estimate is to engage in a dialogue about economic realities to avoid a situation where a utility would need to revise a detailed implementation plan because it is too expensive. This recursive scenario should be avoided if possible as the level of effort and expense to develop detailed implementation plans is significant. Investment funding requests are typically filed separately or through rate cases with a level of analysis and detail described in Chapter 4.

Grid modernization strategic plans are a communication tool to engage stakeholders in a discussion regarding the scope, pace, and magnitude of investment.

3.7 Timing of Strategy Development Activities

The strategy development process steps described in this chapter can either be applied prospectively, at the beginning of a grid modernization effort, or used to realign existing grid modernization efforts where implementation may already be under way.

In the latter case, it can be useful to apply a strategic view to existing efforts that may have started as smart grid initiatives during the past decade. In many cases, smart grid projects largely involved the initial digitalization of distribution systems, particularly smart metering and field automation. These efforts provided foundational functionality that may be necessary to expand upon over the next decade to address a much broader set of objectives for grid modernization.

Hawaii offers a prime example of how smart grid efforts can evolve into a broader grid modernization endeavor. The 2011 Hawaii PUC Order[58] approving foundational smart grid projects and Hawaiian Electric's subsequent Grid Modernization Strategy[59] both demonstrate the DSPx taxonomy and grid architecture concepts (see Chapter 1 for an overview of these concepts). These complementary documents illustrate how to apply principles and clear objectives to strategy development, as well as identify needed capabilities and logical relationships to functions and technologies. The planning process in Hawaii informed the development of the conceptual roadmap that lays out the timing and interdependencies of technology investments. The Hawaiian Electric deployment strategy was shaped by several planning factors identified in their integrated system planning process,[60] including their approach for addressing worst-performing circuits and outage root cause analyses, forecasted customer adoption of DER (including type and location), and utilization of DER for various grid services.

4. Modern Grid Implementation Planning

4.1 Chapter Summary

This chapter provides a systems-engineering approach and techniques for developing grid modernization implementation plans aligned to a grid modernization strategy and/or clearly identified objectives and functional requirements.

CHAPTER OUTLINE

KEY POINTS

This chapter includes a discussion on:

- The application of use case methodology to identify, clarify, and organize system requirements needed to enable specific grid functions
- The process of designing, describing, and managing the engineering of solutions to address requirements
- Factors for evaluating and selecting technology solutions that account for technology fit and risk, organizational capacity, costs, and alignment with priorities and business goals
- The elements of a deployment plan, including work breakdown structure, the sequencing of investments, and engineering cost estimates
- Considerations regarding technology implementation timelines, sourcing options, and strategies for flexible and proportional deployment

4.2 Overview of Modern Grid Implementation Planning

Implementation planning is based on the decisions made in the strategic planning step discussed in Chapter 3. A grid modernization implementation plan involves addressing the following basic questions:

- **Why** is this investment needed (i.e., purpose & objectives)?
- **What** functionality will be delivered by what new/enhanced processes, technology, and/or information? What are the major deliverables?
- **Who** will be involved (e.g., key vendors, consultant, others) and the related organizational structure and responsibilities within the effort?
- **When** will the implementation be completed and key intermediate milestones occur?
- **How much** will this benefit and cost to customers and others?

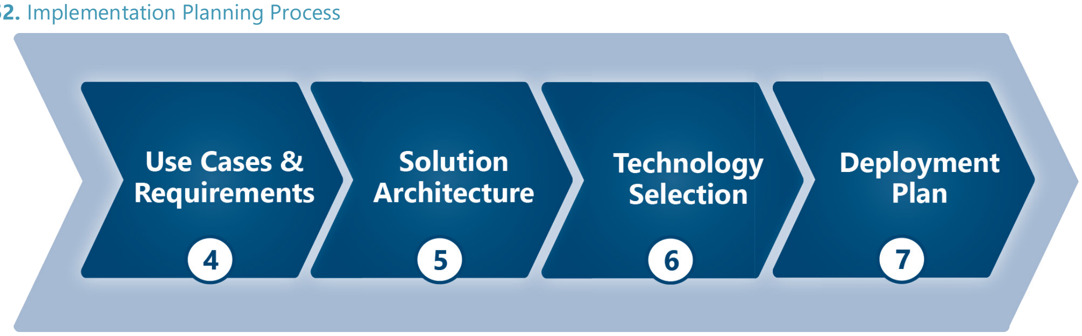
Implementation considerations that go beyond the "why" and "what" is needed—which are described in the previous chapter—involve a sequence of decisions about a) when the solution is needed, b) how fast and what scale should it be implemented, c) alternatives regarding who may provide the solution, and d) the cost-effectiveness of the solution (detailed in Chapter 5).

Implementation planning also involves determining the people, business processes, and technology needed to implement the strategy. These "people, process, and technology" dimensions are interwoven with any organizational changes, especially those involved with the range of customer needs and policies shaping grid modernization.

Four sequential steps to plan grid modernization implementations are illustrated in **Figure 52.** Implementation Planning Process below. The first step in the implementation planning process, Step 4 (use cases and requirements), involves examining potential organizational activities in detail to determine the specific implications on people, process, and technology to enable the specific functions identified in the strategy. These functional assessments are referred to as use cases and provide foundational information to assess the associated people, process, technology, and associated information management requirements.

These use cases and requirements along with the earlier architectural strategies provide the basis for development of the detailed designs undertaken in Step 5 (Detailed Design). Steps 4 and 5 are based on systems engineering best practices used in the electric and other industries. Detailed designs, often referred to as solution architectures provide needed information for subsequently undertaking Step 6 (Technology Selection). The detailed designs and selection of technology within the context of the overall strategy, inform the sequence of technology deployment (i.e., the roadmap, which is articulated in Step 7, Deployment Plan). This general approach to implementation planning is based on best practices across many industry sectors and championed by EPRI for the electric industry starting in the 2000s under the Intelligrid program.[61]

Figure 52. Implementation Planning Process



Each of these steps are described in the subsequent subsections. It is important to recognize that these steps should include clear traceability to the grid modernization strategy, including objectives and architectural strategies, discussed in Chapter 3.

In some instances, there may not be a formal "grid modernization strategy" document that precedes the implementation plan. However, in almost all situations, there will be an organizational strategic business plan, IT enterprise architecture, technology management strategy, and a set of policies that will have informed a grid modernization implementation plan. In these instances, this "strategic direction" should be clearly identified, as it will have set the context and rationale for the plan and related decisions. This strategic context will help clarify the thought process and choices made to shape an implementation plan. A formal grid modernization strategy can be developed later to provide fuller context, logic, and rationale for further modernization investments.

In this context, a grid modernization implementation plan serves as the basis for approval and subsequently (along with any regulatory guidance) becomes the reference for deployment of the associated grid modernization investments.

4.3 Systems Engineering: Use Cases, Requirements, and Solution Architecture

Grid modernization planning leverages systems engineering practices to enable the realization of successful grid designs that satisfy the functional needs of customers, users, and other stakeholders. This approach has been widely adopted by the electric industry, starting with smart grid efforts in the early 2000s. The following highlights key aspects related to grid modernization and is intended to provide context to the internal activities that many utilities perform to develop advanced grid and information technology implementation plans.

4.3.1 Use Cases & Requirements

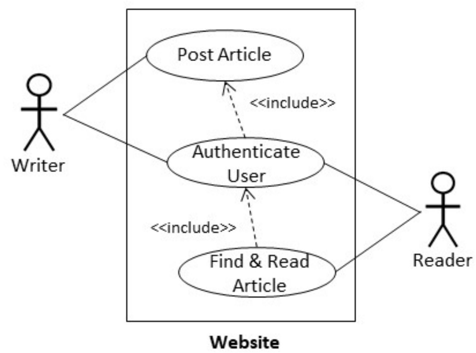
Grid modernization can involve developing new and/or enhancing existing planning, grid operation, and market operation functions, as summarized in Chapter 2 and detailed in Volume I. These business transformation efforts typically involve business process reengineering, which identifies a set of tasks for a specific function that a utility performs to meet a business need or resolve a business issue and considering the roles for people and associated requirements for technology and information.

4.3.1.1 Use Cases

The primary approach for devising grid modernization solutions to achieve a functional outcome is to apply "use case" methodology,[62] which is used in system analysis to identify, clarify, and organize system requirements. A **use case** consists of the set of possible sequences of interactions within systems, including information exchanges with users, related to achieving a specific goal. The systems engineering discipline applies the terms "users" or "actors," which can refer to people, organizations, systems, or devices. The following simple example (**Figure 53.** Website Content Access Authentication Use Case Example) illustrates a use case for granting users permission to upload and access content on a website.

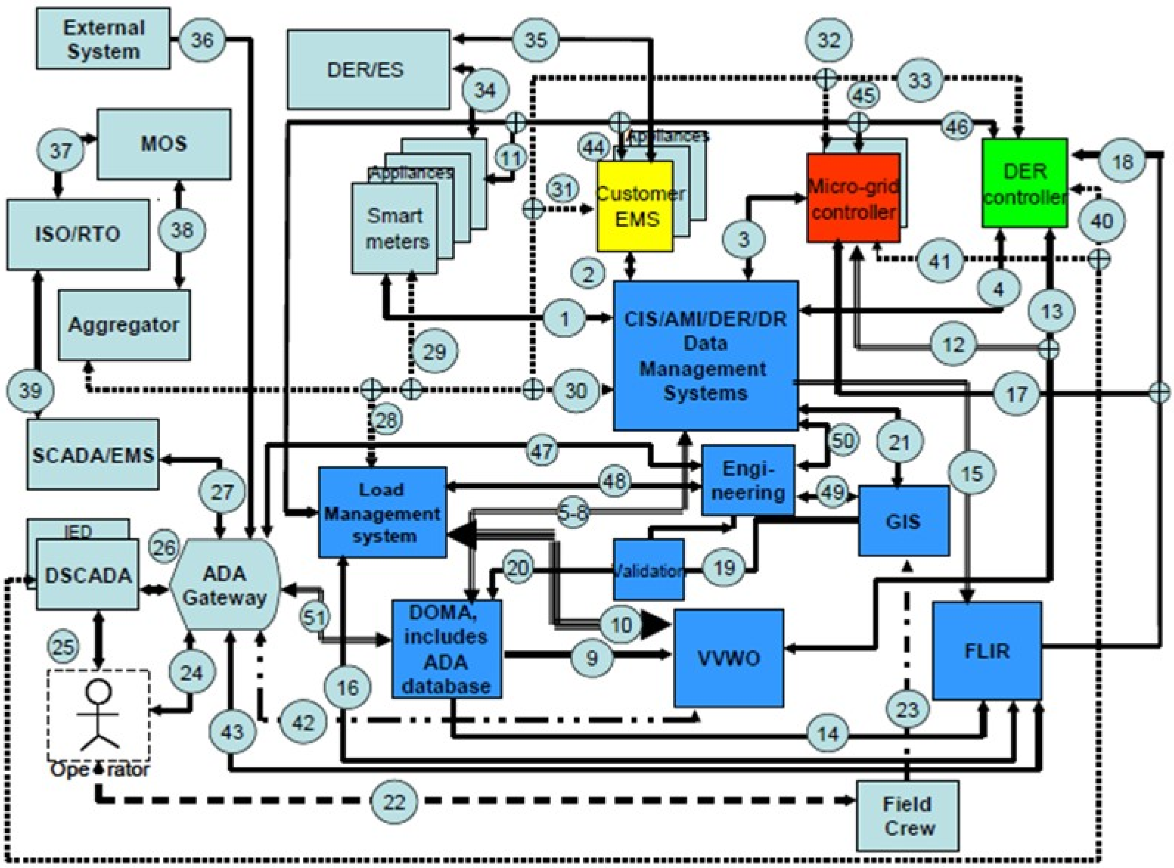
Figure 53. Website Content Access Authentication Use Case Example

Use Case Title	Website Content Access Authentication
Actors	Writer, Reader
Description	1. This use case begins when a content writer or reader tries to access a page that requires authentication. 2. If the writer or reader doesn't have an established session he/she is prompted to enter a user ID and password. 3. If the writer or reader has permission to access the page requested this use case ends in success. Otherwise this use case ends in failure. Alternative: step 2, invalid ID and password entered Display an error message and prompt for the user's ID and password again. Repeat if necessary at most 3 times. Note: This use case links with "Post Article" and "Find & Read Article" use cases



In practice, use cases are often more complex and involve considerable documentation based on a detailed examination of users' information needs to achieve a particular goal or enable a specific function. These efforts can be accelerated by adapting prior relevant use cases developed by others, including use cases in the substantial public use case website-based repository maintained by EPRI.[63] Utilities, national labs, and others have contributed grid modernization related uses cases to these sites over the past 15 years. One example is a use case involving distribution grid management from the EPRI repository; the resulting interface diagram is shown in **Figure 54**.[64] In this use case, the requirements for the various interfaces are identified. The extensive number of interfaces, particularly related to utility operations and systems, highlights the interdependent nature of the core platform, as described above, to operate the distribution grid.

Figure 54. Distribution Grid Management Use Case Interface Diagram Example



4.3.1.2 Requirements

Use cases are also employed to determine functional and non-functional system requirements. A functional requirement describes what the system should do, whereas a non-functional requirement provides directions or constraints on how the system should do so. The following simple examples highlight the difference:[65]

- Functional requirement: A system must send an email whenever a certain condition is met (e.g., when a customer registers).
- Non-functional requirement: Emails should be sent with a latency of no greater than 12 hours from such an activity.

Requirements articulate precisely what is required of a technology solution (e.g., related to software, communications, and grid devices). They also convey this precise need to all parties involved in developing and implementing the solution internal to the organization (e.g., the planning, grid operations, market operations and IT teams), as well as to technology solution vendors. These requirements provide the fundamental control reference (i.e., specifications) for the procurement and implementation of technology solutions and related systems.

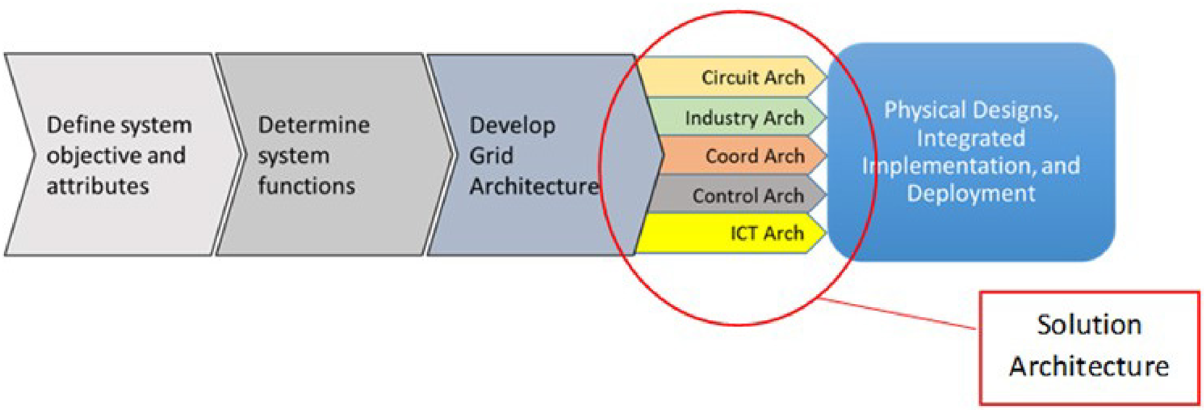
As such, it is essential that these requirements are traceable back through use cases to the identified functions, capabilities, and objectives in the strategy. This traceability is key to ensure the subsequent technology selections and implementation are aligned to the desired strategic outcomes, including providing value to the customer.

4.3.2 Solution Architecture

The use cases and associated requirements inform the implementation of needed business processes and the undertaking of the detailed design (through a solution architecture development process). The term **solution architecture** is often used to describe the process of designing, describing, and managing the engineering of the solution in relation to specific business needs and related functionality. It also refers to the structure and interrelationships of all the components involved to achieve a specific capability or function, which can be depicted at varying levels of complexity.

The objective of the process is to articulate more detailed designs derived from the architectural strategies and principles discussed in Chapter 3. A high-level depiction of the solution architecture process, in which detailed engineering is undertaken for various components of an envisioned system (i.e., industry, physical circuit, coordination, control, information, and communication components), is illustrated below in **Figure 55**.

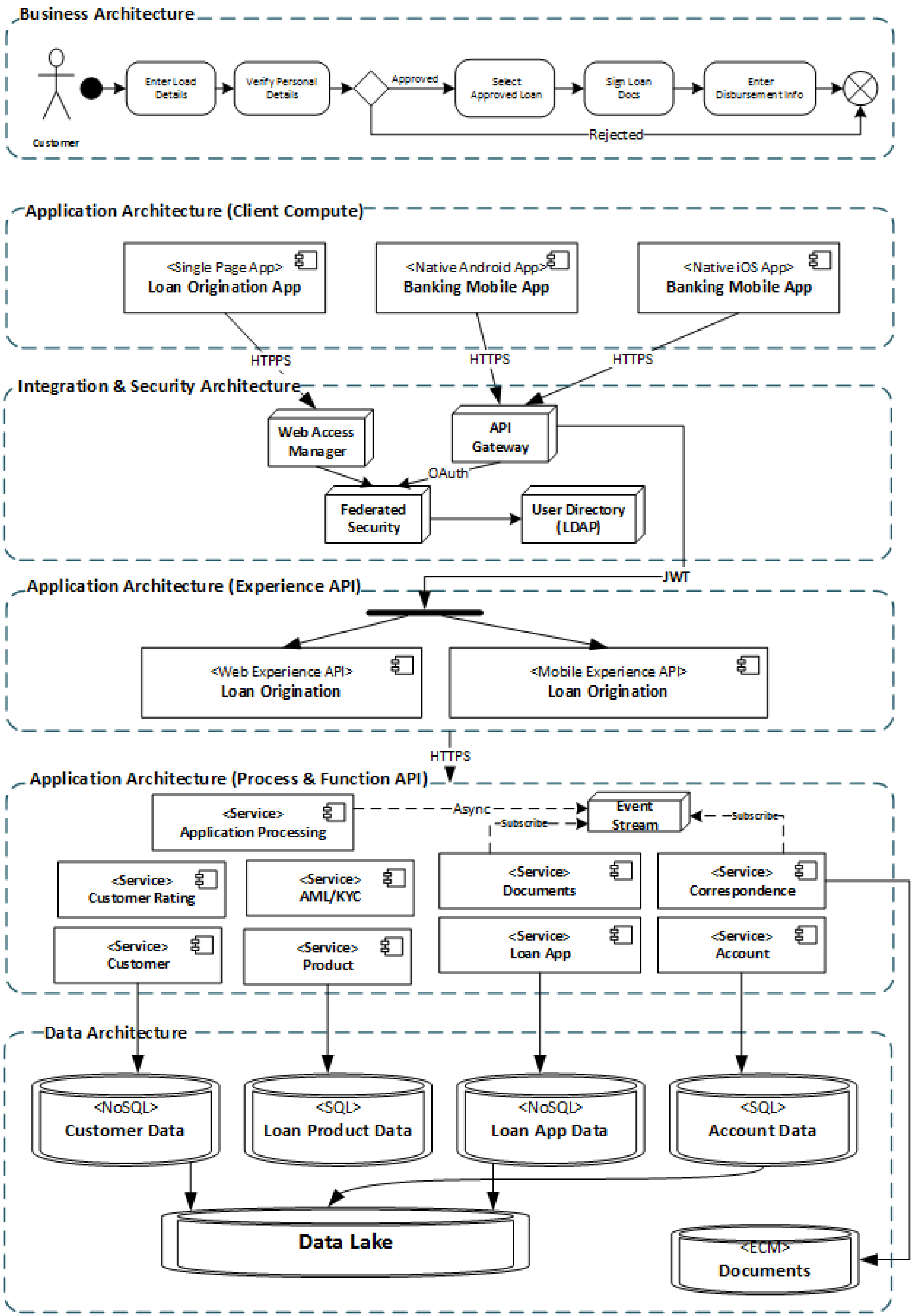
Figure 55. Grid Architecture-Engineering Design Process



Two key parts of creating a solution architecture are identifying technologies and integrating design considerations related to system integration and data management. This technical architecture results in a chosen set of technologies that works together to meet the requirements identified to accomplish the objectives as discussed. This detailed engineering exercise results in specifications according to which the resulting solution is defined and ultimately managed and delivered.

The solution architecture typically includes the development of a formal description of a system which would include a detailed plan of the system at technology component level to guide its implementation, specifically, the decomposition of a system into different components and their interactions to satisfy functional and nonfunctional requirements. Additionally, the solution architecture defines the structure of components, their interrelationships, and the application of the architectural principles to govern their design and evolution over time.[66] Solution architecture serves as the detailed blueprint for individual technology components, interfaces, and their relationships to the business processes of the organization. An example of a simple solution architecture for banking is shown in **Figure 56**.

Figure 56. Example Banking Solution Architecture



As this illustration suggests, solution architecture methodology is widely used in many industry sectors and employed by utilities. This methodology has been codified for smart grid and grid modernization efforts through efforts by the GridWise Architecture Council (GWAC)'s interoperability framework[67] and the National Institute of Science and Technology (NIST).[68]

4.4 Technology Selection

In this step, the system requirements developed through the formulation of use cases inform the selection of technologies to be implemented. This step involves examining trade-offs between alternative technology solutions prior to making final selections. Alternative technology solutions may differ with respect to cost, implementation timeline, the ability to support long-term objectives for needed functionality, and other factors. Technology drivers and targets shaped by these factors become critical variables when examining and selecting alternatives.

For instance, a timeline should be developed for each alternative that accounts for the maturity of all the technologies and processes (e.g., interoperability standards implementation) that are needed to successfully integrate and deploy a given solution. This type of analysis will provide insight into the complexity and timing dimensions of the set of alternatives.

Technology solutions should also be assessed in terms of their ability to support advanced functional requirements envisioned for the future. A smart inverter deployed today, for example, can be applied in a "dumb" fashion, then later operated using its autonomous smart control settings, and later still integrated with telecommunications and ADMS/DERMS control for dynamic settings management. Conversely, it may be appropriate to apply the next version of smart meters to achieve the functionality that this type of device might provide through its sensing capability. Applying this type of analysis to compare and select technology solutions is a key step in developing an integrated grid modernization roadmap and for providing cost-effective delivery of functionality.

4.4.1 Technology Solution Stack

The selection of technology solutions should be undertaken in consideration of the technology stack as presented within the discussion on "layering" in Section 3.5.2 (Architectural Considerations) and presented in Figure 34 on page 60. As discussed in that section, a technology solution stack will involve both a subset of technologies that comprise a core platform and single purpose applications that leverage it. The systems engineering approach to examining alternatives should include determining how well they support the development and integration of core components needed to enable needed functionality over time while taking into account key architectural considerations.

These core components comprise the essential technologies that provide a foundation for a modern distribution grid. DOE's Modern Grid Initiative,[69] EPRI's research,[70] and other efforts over the past 15 years have consistently identified five categories of foundational technologies:

- Physical infrastructure (e.g., wires, transformers, switches)
- Advanced protection and controls
- Sensing and situational awareness
- Operational communications
- Planning tools and models (e.g., DER & load forecasting, power flow analysis)

Above the core platform sit modules, or applications, that can be added as additional functionality is needed. One example, integrated volt-VAR optimization (IVVO), is an application that may be needed to address more sophisticated management of voltage variability on a distribution system. IVVO can be added when needed, leveraging the prerequisite sensing, controls, and communications within the core platform. Building out the core platform should be undertaken to enable future functionality and therefore should be considered differently in terms of their greater inherent long-term value to customers. The selection of technology solutions should consider future capabilities needed in the core platform, as well as how it can implement and integrate, in a modular fashion, additional application needed over time.

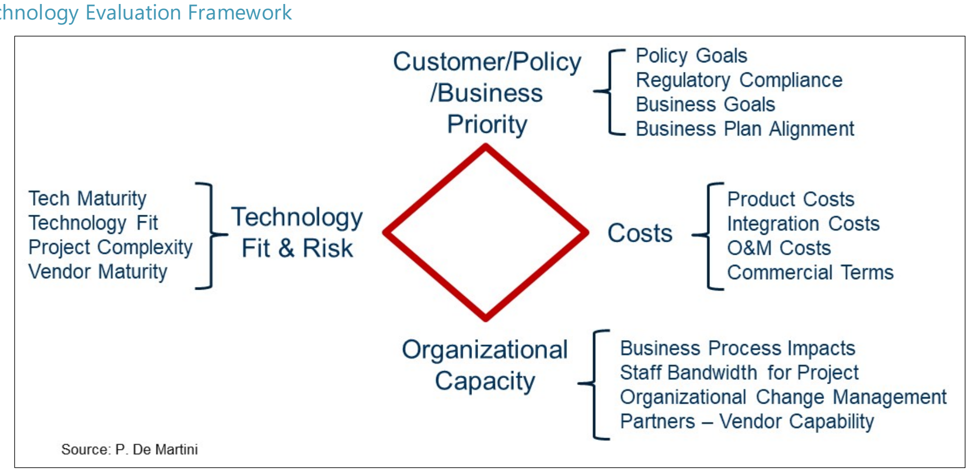
However, this does not mean that every situation needs all of these types of technology or needs a system-wide deployment of the core components. The scope and pace of deployment is based on the unique situation of each utility as determined by many factors, including their starting point, requirements for meeting policy objectives and providing customer value, forecasts of load growth and DER adoption, and criteria for assessing and selecting technologies. Specific technology choices will require careful consideration with respect to system integration, interoperability, and security. Where grid modernization efforts have already begun, another consideration is how to enable further development in an efficient and effective manner.

4.4.2 Technology Evaluation

The solution architecture and related technology stack will typically be agnostic regarding vendor-offered technologies and will require a follow-on step to identify and source specific vendor products to meet technology and equipment needs. Sourcing is usually done through a competitive procurement. The resulting vendor alternatives need to undergo a technical and non-technical evaluation to determine the appropriate selection.

A general framework for technology evaluation involves assessing potential technologies/equipment on four basic dimensions; Customer/Policy/Business Priority, Technology Fit and Risk, Organizational Capacity, and Costs. These are illustrated in **Figure 57** and discussed below.

Figure 57. Technology Evaluation Framework



4.4.2.1 Customer/Policy/Business Priority

This screening dimension assesses proposals from vendors with respect to how well they satisfy the technical requirements developed through the detailed design phase, as well as the extent to which they serve priority needs with regard to addressing policy, regulatory, and utility business goals.

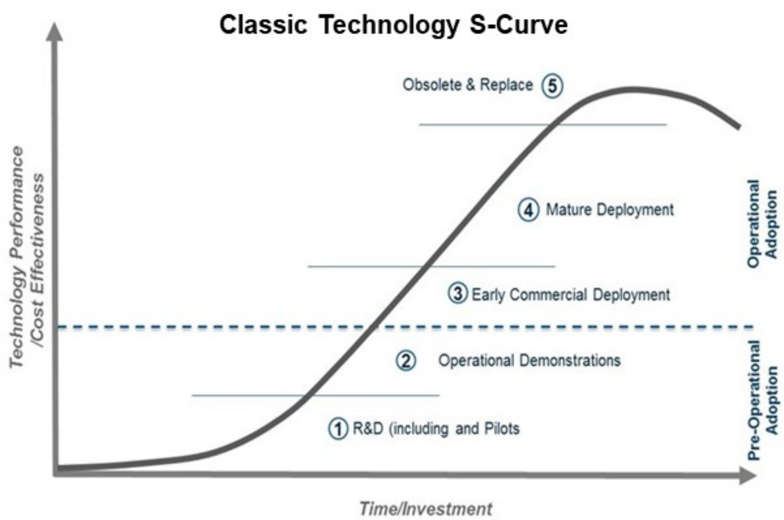
4.4.2.2 Technology Fit and Risk

This screening dimension involves examining whether the proposed vendor solution meets the functional and non-functional technical requirements and whether the maturity of the solution fits the technology adoption strategy for the organization. Technologies that are either pre-commercial in their development cycle or overly mature may pose risks for the utility.

Regarding technology fit, it is important to determine the compatibility of vendor products with utility systems. For example, software solutions offered by vendors may require certain hardware technology to operate which is not employed by the utility. Likewise, database technologies used by a utility enterprise system may not be compatible with certain software solutions. These issues are analogous to smart phone operating systems and the phone hardware, for example, trying to run Android's operating system on an Apple iPhone. Often, non-functional requirements cannot all be met (beyond basic compliance requirements) and may require additional vendor technology development or adaption to a utility's enterprise IT standards. Identified vendor solution development/adaptation changes to meet both functional and non-functional requirements introduce cost, schedule, and performance risk.

Additionally, the commercial maturity of the technology/equipment solution in relation to a utility's technology adoption strategy may screen out certain vendor solutions. The classic technology S-curve in **Figure 58** illustrates the commercial maturity of a specific vendor's solution in relation to market adoption and by extension the maturity of the product in terms of its ability to meet utility requirements with respect to performance and timing.[xxv]

Figure 58. Technology Adoption Maturity S-Curve

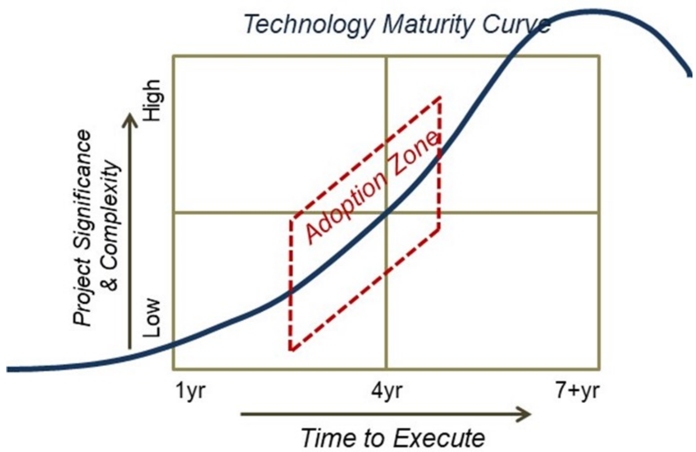


"Pre-operational" technologies may require further development, testing, and demonstration before they can be expected to perform according to the engineering specifications required for reliable

[xxv] Modern Distribution Grid Volume II provides a detailed discussion of technology maturity curves with examples.

operation, hence they will take longer to deploy. Utilities will adopt mature technologies more readily since their performance is well understood and bugs are resolved. In some cases, it is necessary to adopt less mature technologies that are in the early commercial deployment phase; rarely are technologies in early development adopted into grid operational systems given the significantly higher risks involved.

Figure 59. Technology Adoption Strategy Example

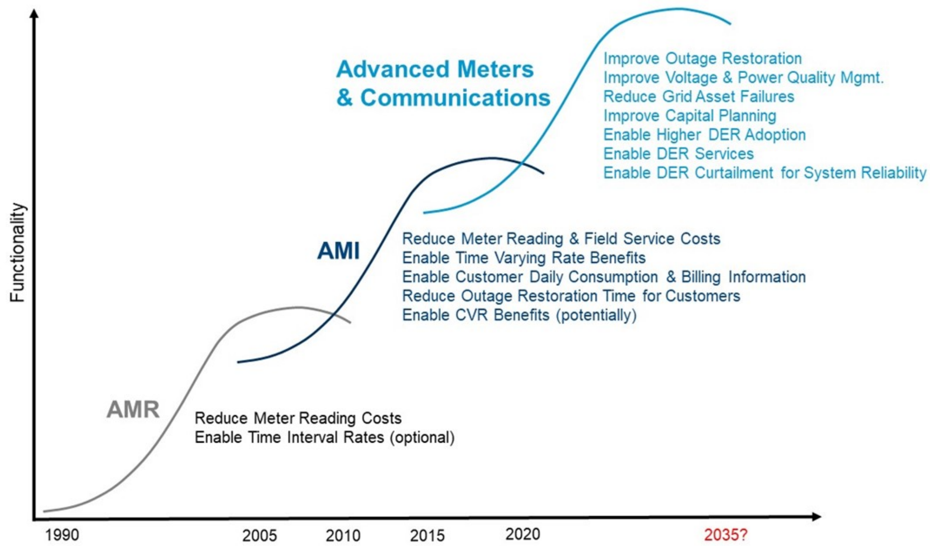


Source: P. De Martini

Adopting a technology that is very mature or obsolete is also typically avoided to reduce the risk of stranded investments, as technology vendors generally will not support their products indefinitely. This is called product end-of-life (EOL), which refers to when a vendor stops marketing, selling, or supporting the product. Most recently, for example, the decision by the major mobile carrier to EOL 3G cellular service has created issues for those connected grid devices. This has also occurred with demand response devices that received paging signals that have been systematically rendered inoperable due to the shutdown of paging systems across the country. Therefore, determining both the desired technology maturity and the expected operational timeline are important to consider.

To illustrate these issues, consider the challenge of deciding which version of residential metering to employ in a new deployment to support time-varying rates and DER adoption, as well as enhanced grid operations. In **Figure 60.** Technology Innovation Multiple S-Curves below, automated meter reading (AMR) meters are functionally limited and past their peak adoption period (see Phase 4 above). However, the issue is more challenging when considering whether to deploy the last generation of AMI meters that originally came on the market in the late 2000s. This generation of smart meter products is now quite mature and offers solid value as business cases and subsequent experience have demonstrated over the past decade. However, the next generation of advanced meters has been introduced into the market, which offers considerably greater performance and can address more potential grid value than the AMI meters. The overlapping S-curves, as shown below, create a challenge for decision makers.

Figure 60. Technology Innovation Multiple S-Curves



Source: P. De Martini

If, as a simple observation from the figure suggests, metering technology has about a 15-year product lifecycle, it will remain functional for a total of 20 years or more. The current AMI meter is a very stable device with comparatively low operating risk given the tens of millions of similar devices deployed. The functionality of today's AMI meters may meet immediate priority requirements, but not necessarily desired future requirements (e.g., the ability to use the meter as a sensor with computer capabilities to support advanced grid operations and observability needs). Given the advent of the next generation of smart meters that will offer greater functionality, the utility faces a decision of whether to deploy the current generation or wait to install the next. However, there are few deployments with advanced meters, and the technology may still be evolving in terms of software code and hardware refinements. Therefore, their deployment will involve more unknowns and potentially be more complex due to the added functionality.

To resolve this question, it is helpful to consider the technology adoption strategy with its timeline and potential risk mitigation measures for deployment and vendor management. If these issues can be addressed, then it may make sense to select the latest meter product.

4.4.2.3 Organizational Capacity

A key aspect of whether a technology can be successfully adopted is whether the utility has the organization bandwidth and skills to support the project and whether the vendor has sufficient resources to concurrently support both the continuing product development as well as the industry deployments of that product. Understanding the capacity of an organization to undertake such efforts is an essential part of risk management planning, which is discussed below in more detail. Organizational capacity considerations may include business process re-design, which may be required for integrated planning and workforce development efforts to marshal the appropriate skill set.

4.4.2.4 Costs

Vendor technology costs typically will include the product cost, ongoing license fees, and O&M support, plus professional services for configuring the utility's environment, business processes, user interfaces, and other areas. Additionally, a product will require integration with other grid modernization and/or enterprise systems. These integration costs may be based on information developed by system integrator consultants, vendor staff, and/or internal utility personnel. Also, commercial terms for the delivery and implementation/deployment of a technology will include contractual terms and conditions (e.g., schedule delay penalties, performance guarantees) that seek to assign certain risks between the vendor, utility, and/or system integrator. These terms may change the final contract price and effective cost.

4.5 Deployment Planning

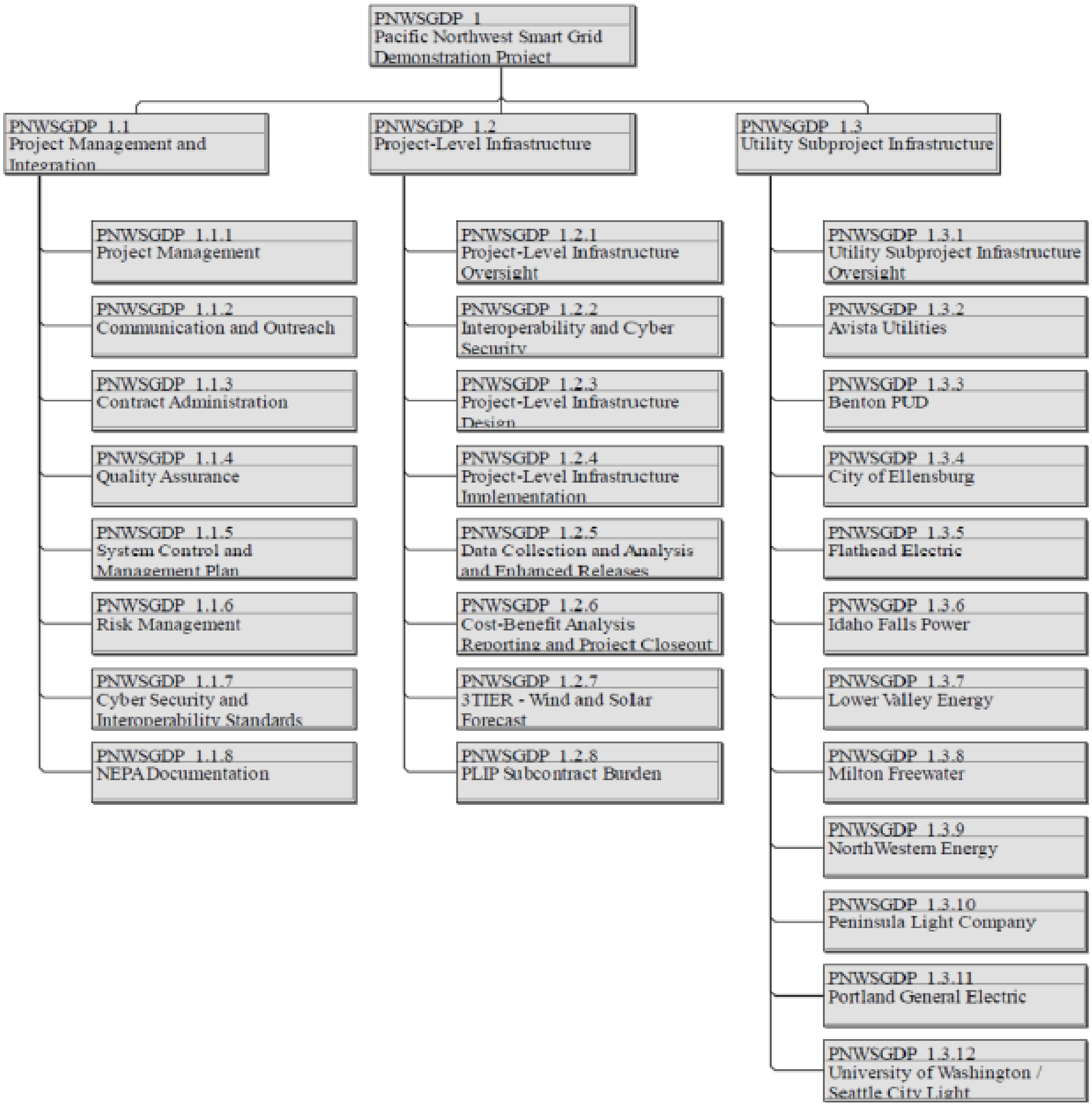
A grid modernization implementation plan is effectively a project (program) plan for the implementation of a specific set of technologies. A project plan should include clearly defined objective(s), scope, schedule, budget, and needed resources, as well as a discussion of risk mitigation. The implementation plan objectives are the customer, policy, and/or business objectives identified in Chapter 3. The balance of the project plan is driven by the tasks that need to be performed to implement the proposed technology and/or equipment. This involves a) defining tasks, b) sequencing the tasks, c) estimating the associated costs, and d) developing an overall schedule of implementation tasks reflecting cost and resource considerations. The cost-effectiveness of an implementation plan is discussed in Chapter 5.

4.5.1 Defining Activities

The activity definition process begins with a systematic articulation of the tasks that are required for the implementation. This type of activity decomposition is called a work breakdown structure (WBS) in the project management discipline. More specifically, the Project Management Institute Book of Knowledge defines WBS as "a hierarchical structure of things that the project will make or outcomes that it will deliver."[71]

Beyond development of the WBS, it is necessary to further define the individual tasks in terms of the technology/equipment, resources and other elements needed to execute each task's deliverable(s). It is important to note that these tasks are not the deliverables themselves but the individual units of work that must be completed to fulfill the deliverables that collectively implement the plan's objectives. A grid-relevant example of a WBS is from Pacific Northwest Demonstration Project[72] below in **Figure 61.** Pacific Northwest Smart Grid Demonstration Project WBS. A similar hierarchical decomposition is used in this grid example as in the conceptual example above.

Figure 61. Pacific Northwest Smart Grid Demonstration Project WBS

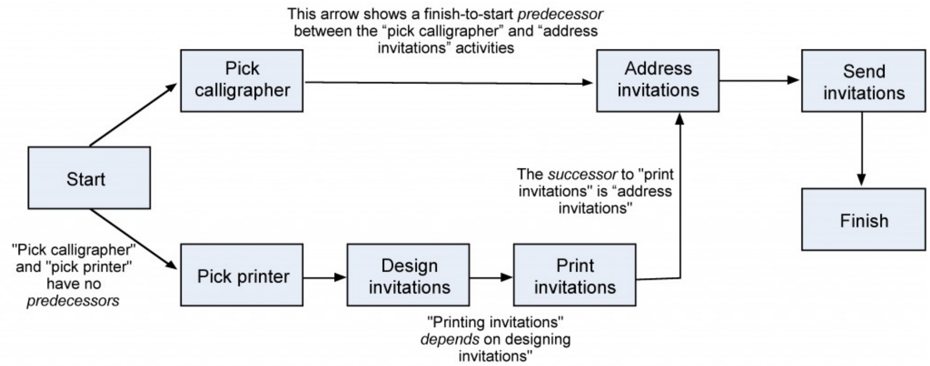


4.5.2 Sequence Activities

The next step is to identify the sequence of activities via a logical flow based on interdependencies to achieve the overall implementation objectives. The Project Management Institute[73] describes this process as "identifying and documenting relationships among the project activities." Sequencing provides important information to the project planning; it provides information about how the tasks are related, where the risk points are in the schedule, how long it will take as currently planned to finish the project, and when each task needs to begin and end.

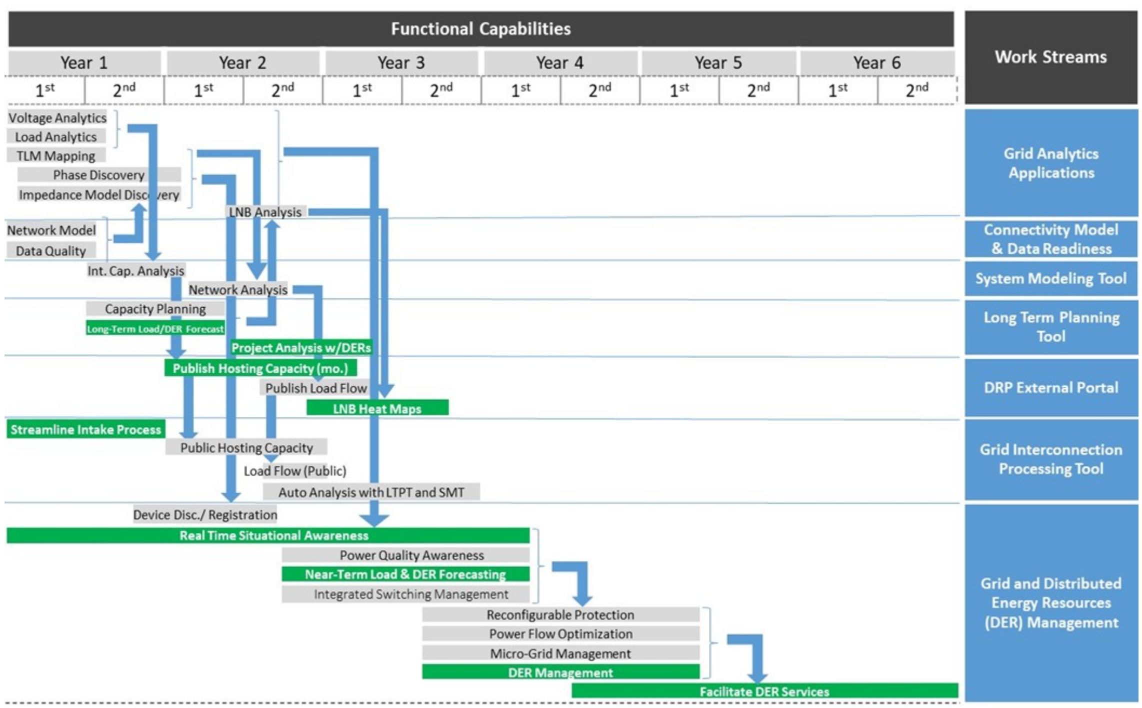
Sequence diagrams provide a graphical view of the activities and how they relate to one another. These tasks are those identified in the WBS. Sequencing involves arranging the WBS tasks into a sequence based on the interrelationships with other tasks, as well as how they may be constrained by time or resources. In a simple example involving wedding planning, the WBS tasks are arranged into a logical sequence shown in **Figure 62** below.

Figure 62. Conceptual Activity Sequence Diagram



The sequence diagram is in the form of a schedule but is used to identify key scheduling information and interfaces that ultimately go into more user-friendly schedule formats, such as milestone and Gantt charts. An example of a hypothetical grid modernization related activity sequence diagram is provided below in **Figure 63**.

Figure 63. Hypothetical Grid Modernization Project Activity Sequence Diagram



Source: Adapted from Southern California Edison

All WBS tasks must be included in the sequence diagraming to support development of a schedule. Omitting activities from the sequencing could change the overall schedule duration, estimated costs, and resource allocation commitments. As such, a key benefit of this process is that it defines the logical sequence of work to obtain the greatest efficiency given project constraints.

The resulting sequence of activities enable specific capabilities and functions, which may stagger during deployment of core technologies. For example, **Table 2.** Xcel Colorado's AMI Functionality Sequence below shows Xcel Colorado's deployment timeline and the enabled business capability for AMI, IVVO, and FAN for distribution enhancements.[74]

Table 2. Xcel Colorado's AMI Functionality Sequence

Year	# of AMI Meters (Cumulative)	Business Capability	Integration Detail
2017	0	IVVO device and FAN deployment only	
2018	0	IVVO device and FAN deployment only and the Company will file an application that presents a plan to activate the HAN in March of 2018 pursuant to Section III. G.2 of the Settlement Agreement.	
2019	13,000	Head End	Communications Network
		Billing	Register usage data
			Load profile
			Energy/demand
			Interval data
		Event Processing	Billing quality events and alarms
			Temperature
		Support IVVO	Interface to ADMS
		Reporting	As Required
		Analytics	Deployment use case only
			Weekly system reconciliation
		OTA (Over the Air)	Support meter reconfiguration
2020	175,000	OTA (Over the Air)	Meter programming – rate changes, additional measured quantities, etc.
			Network equipment updates – AP's, Bridges, etc.
			Firmware updates
			Provide critical reporting to support business function Meter Reconfiguration for other use cases
		Customer Care	Real-time data access for customer agents for billing, issue resolution, quality of service, etc.
			Provide critical reporting to support business function
		My Account	Provide meter usage information to customers, per Section III. H. of the Settlement Agreement
			Customer billing information
			Provide critical reporting to support business function
2021	570,000	My Account	Up to last regular read
		Analytics	Theft use case
		Connect / Disconnect	Upgrade processes and systems to support remote connect / disconnect function
		Events Processing	Outage notification Connectivity model (GIS data)
			Meter events
			Network events
			Head-end events
			Reporting
			Support meter reconfiguration to enable customer changing rate plans
2022	1,050,000	Analytics	Non-theft use cases
		My Account	On demand reads for data since last read Integrate with mobile app
		Data Warehouse	Reporting
2023	1,500,000	Complete meter rollout	
2024	1,600,000	Complete meter rollout	

4.5.3 Deployment Timing Factors

4.5.3.1 Deployment Aligned to Customer Value

Modernizing the distribution system should provide value for all customers to be sustainable. In addition to traditional customer value derived from the safe, reliable delivery of power, there are three strategic concepts considered today by policy makers and others:

- Adopt technology innovations to increase customer value, system reliability, and resilience
- Enable customer choice at the pace of customer DER adoption
- Enable, where practical, opportunities for DER to provide services to achieve system efficiencies or provide enhanced reliability and resilience

As discussed above, the pace of deploying foundational investments can be tied to the expectations or plans of customers and third-party merchants. Therefore, foundational investments may need to support an increase in unplanned, organic customer DER adoption, the deployment of merchant-based grid services driven by wholesale market opportunities, the application of DER as non-wires alternatives to distribution investment, novel grid configurations presented by microgrids, and other possibilities not yet envisioned.

A challenge to consider is that the pace and scope of change reflected in distribution investment plans may not be sufficient to meet evolving customer needs and policy objectives. This is due in part to DER adoption, which may occur on a timeframe faster than new grid infrastructure implementation. For implementation planning purposes, it is important to consider the different timing and functional capabilities that are required for DER integration and utilization,[xxvi] as well as their respective incremental costs and benefits.

4.5.3.2 Grid Technology Deployment

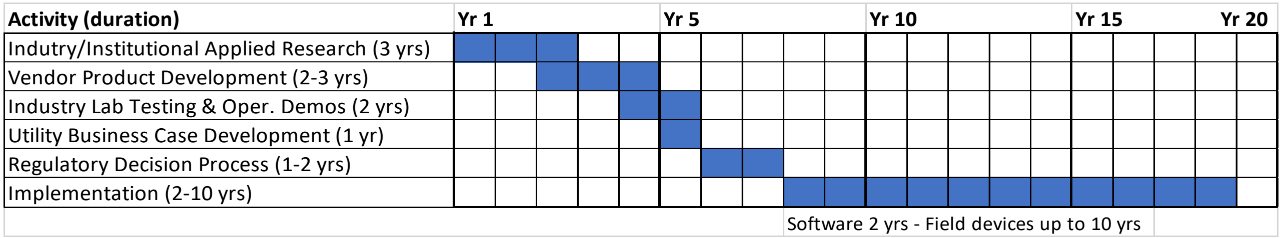
Reducing uncertainty is important as the time cycle for developing technology products from applied research through system-wide deployment is lengthy and may take up to 20 years from beginning to end. At first glance, many believe this time cycle is far too long—incorrectly comparing the adoption cycle of consumer electronics from the time they reach market to consumer purchase, which is relatively faster. Looking more closely, it becomes clear why the overall duration for technologies deployed at scale in the grid or grid operating systems may take 5–10 years or more.

First, the time before a product is commercially ready for system-wide deployment needs to be considered, as described above. Also, the regulatory approval process through general rate cases or separate applications can add between 1–2 years depending on the size and complexity of the proposal. Deployment timelines are driven by the technology to be deployed. Large operational software can take about 2 years, while system-wide deployment of field devices can take up to 10 years, depending on the number of devices and the complexity of the field replacement/installation.

Figure 64 below is a conceptual timeline for product development and adoption by electric utilities. This timeline does not reflect potential re-work loops if products do not pass tests, if business cases do not pass regulatory review, or if products fail or become prematurely obsolete during deployment.

[xxvi] Integration refers to the ability to interconnect and successfully undertake grid operations with increasing levels of DER, while utilization refers to the ability to actively apply or control DER to maximize their value to customers and the grid operator.

Figure 64. Operational Technology Development & Adoption Timeline



Source: P. De Martini

Additionally, product development in the electric industry is often ad hoc. Various technology firms work on different solutions at differing stages of development that will combine to enable the platform discussed. This means some products are fully available now, or are at least in a demonstration phase that precedes utility business case development and the regulatory approval process. As such, it would be beneficial if the industry (e.g., utilities, regulators, tech firms) developed a vision for the grid of the future and for policy to support RD&D efforts to accelerate vendor product development and testing.

The main point of this Guidebook, as well as the Modern Distribution Grid (DSPx) Series (all 4 volumes), is that **functional capabilities and related technology investments should be driven by customer needs and public policy**. This line of sight approach inherently aligns investment to customer and societal value. However, the complexity of implementing and integrating various technologies, perhaps at an early stage of maturity, makes deployment more challenging, and increasingly risky.[75]

Risks also include the potential to mismatch timing with need, as highlighted above, on the relatively fast cycle of DER and customer technology innovation and adoption in relation to grid technology product development, investment approval, and the deployment time cycle. There is a tendency for some decision-makers to force technology choices (e.g., types of DER) without adequately implementing efforts to advance grid capabilities needed to support them in an operational environment.

Additionally, grid modernization is starting from a large existing infrastructure that is a combination of old and new elements. Modernization plans needs to consider how to manage the transition from, or integration with, legacy systems while continuing to provide reliable and safe grid operation. Therefore, "how" technologies are deployed is critically important.

4.5.3.3 Flexible Deployment Approach

The many considerations raised in this Guidebook point to the need for a flexible, adaptive approach to the implementation of a modern grid. Managerial flexibility, for example, is needed to defer, avoid, proportionally deploy, and adapt to technological innovation. This is especially necessary given the expected long transformation time that modernization will take in most instances. Such flexibility designed into a roadmap and implemented can create value for customers as described below in the discussion on real options. There are two complementary ideas on crafting such a flexible approach: logical progression and proportional deployment.

Logical Progression

Most of the discussions in the United States are about the evolution from Stage 1 to Stage 2 functionality, as discussed in this Modern Distribution Grid series and presented in Figure 1. Distribution Grid Evolution Complexity on page 10. Nearly all U.S. distribution systems today are in Stage 1, with some utilities taking steps toward Stage 2; however, given recent pressures to examine alternative grid configurations that may apply community-based microgrids, there is a need in some cases to examine transitions into Stage 3. Thus, every jurisdiction/utility situation will need to first assess the starting point—the "Start Here" point within Stage 1—given the foundational capabilities needed to support advanced functions, as discussed in Chapter 2. There is no generic starting point applicable to all jurisdictions and utilities. Next, jurisdictions/utilities need to clarify the objective(s) and corresponding functionality desired in a defined period of time. There must be clear functional objectives and time horizons for desired outcomes. Too often, grid modernization and distributed resource integration stakeholder discussions are stalled due to ambiguity on desired customer and policy outcomes, and in which the "perfect" solution is clouding the "good enough" solution that achieves the majority of net value potential for all customers.

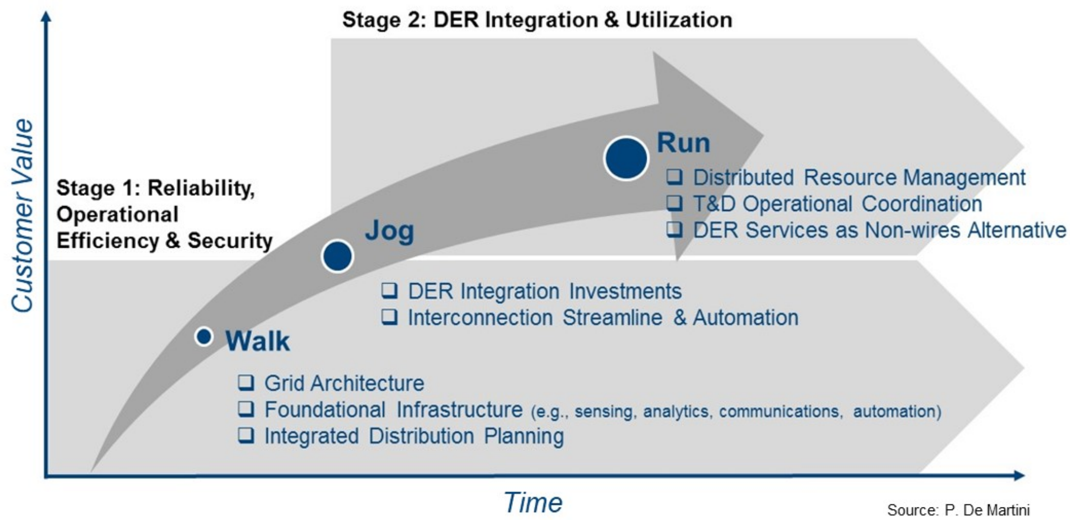
Too often, grid modernization and distributed resource integration stakeholder discussions are stalled due to ambiguity on desired customer and policy outcomes, and in which the "perfect" solution is clouding the "good enough" solution that achieves the majority of net value potential for all customers.

The next consideration is to identify a logical progression in the relative sophistication or complexity of a functional enhancement or new functionality in relation to the starting point and what level of functionality is needed. If the process changes are significant and the technologies are relatively immature or implementation is complex, it probably makes sense to take a multi-step approach. The recommendation here is to start with the most simple and mature solution ("Walk"), then add additional capability as available/needed ("Jog"), and when appropriate migrate to the final step ("Run") of functionality desired as illustrated in **Figure 65.** Walk-Jog-Run Example below. This type of "Walk-Jog-Run" stepwise approach[76] follows two important ideas that should shape any grid modernization effort, Occam's razor[xxvii] and Pareto's Principle.[xxviii] In effect, the objective of modernization is to identify the simplest path to achieve the desired outcomes and taking a series of steps focused on those investments that yield the most customer value. It is also important to note that, depending on the pace of policy, technological advancements, and levels of deployment, states may be in the "Walk" stage for certain components and "Jog" stage for others.

[xxvii] Occam's razor is a principle advocating that when two competing theories make exactly the same predictions, the simpler one is often better.

[xxviii] Pareto's Principle (or the 80/20 Rule) is a business rule of thumb that recognizes the disproportional relationship between certain inputs and related output. For example, as Pareto noted, 20% of the peapods in his garden contained 80% of the peas.

Figure 65. Walk-Jog-Run Example



A Walk-Jog-Run approach is applicable to manage such a transition. For example, in the case of hosting capacity analysis, one might start with more simple analysis leading over time to more sophisticated uses. A Walk-Jog-Run approach for the implementation of a hosting capacity analysis capability would begin with a) providing indicative information to DER developers through heat maps, followed by b) its use in annual planning to forecast additional upgrades to enable greater customer adoption of DERs, and then c) applying the DER information in reducing the time for interconnections decisions with on-line automated tools.[77] Each of these steps is based on increasing sophistication from the underlying planning tools that are in development by technology vendors. Pilot programs have also been used to explore further sophistication and in determining appropriate levels of functionality.

Flexible Deployment

Grid investments need to provide tangible value for customers and all stakeholders, including utilities. The challenge is addressing the uncertainty in the scope and pace of customer needs and the effects of policies. As described, grid modernization involves multi-year (potentially a decade or more) efforts for technologies to be deployed. This dynamic creates several risks related to technology obsolescence due to rapid innovation, implementations mismatched to needs (under-build and over-build), and misalignment of investment to customer value. It is essential that any plan be linked to a robust planning process and methods that are based on clearly understood and transparent assumptions of customer needs, policy objectives, and corresponding forecasts of distributed energy resources and load.

Designing flexibility into an implementation plan can help mitigate these risks and increase customer net value. Such flexibility leverages effective architectural principles (described in Chapter 3) along with interoperability-based open standards as a starting point. Flexibility involves designing optionality into a multi-year deployment. Such optionality could include technology on-ramps to accommodate important advancements that develop, including intermediate decision points to reprioritize modular deployments—for instance, by deferring installation on one feeder to focus on another as needs change. Also, leveraging investments in a common core platform (even incrementally) will enable the ability to deploy tailored bundles of technologies in the field to address the specific needs proportionally. The economics and customer value of an investment may support a system-wide or full implementation, as is the case with certain software systems.

In addition, deployments generally involve relatively large expenditures on a system-wide level that can be deployed first on a localized basis to address specific needs and, over time, expand based on needs to encompass the whole system. This type of surgical approach can allow for changes in prioritization of deployment as customer needs and system issues may evolve over time. An annual reassessment of the prioritization of grid modernization investments, not unlike those for the physical grid, could be done. This would require a different approach to considering grid modernization investments as less deterministic and instead as more of a set of investments to be deployed in an agile manner. For example, instead of using the typically deterministic AMI business case approach of the 2000s,[78] allow instead annual capital and expense re-prioritization in response to changes in needs. This is not unlike the methods traditionally used in annual grid planning to address reliability and safety needs. This would require regulatory review of reasonableness to allow such flexibility in implementation.

4.5.3.4 Legacy Transition Factors

All grid modernization planning starts with an assessment of the current state of the distribution system to understand the starting point. These starting points are not green fields—they are a compilation of decades of prior investments with a range of older and newer technologies and often include structural constraints that may require adjustment.

Historically, grid systems/devices were largely proprietary systems, unlike modern information and operational systems that are based on more effective architectures and interoperable standards. Initial deployment planning efforts, therefore, need to consider the integration of modern information and telecommunications with distribution control systems and advanced field devices on legacy cyber-physical infrastructure.

Many of these new systems need to interface with each other as well as with older systems to function and achieve operational benefits. Unfortunately, integration of open interoperable systems with legacy proprietary vendor systems can lead to very expensive system integration costs—as much as 3–5 times the cost of the underlying new software application. The architectural approaches discussed earlier can mitigate some of this, but not all will need to be considered in any implementation plan.

Most of the older systems had few security features and did not account for cyber security sufficiently in today's more connected environment. This is especially true given the threat levels addressed in the NIST guidelines.[79] It is also important to keep in mind that about 97 percent of the total circuit miles of the U.S. electric grid is distribution and, as such, it is not explicitly covered by the North American Electricity Reliability Corporation (NERC) Critical Infrastructure Protection Standards[80] or other similar cyber security imperatives.

The distribution grid is regulated by state commissions or local boards. The evolution of a distribution with large numbers of DER and Internet of Things (IoT)-connected devices is creating a significant gap for electric system security. New grid technologies are increasingly meeting cybersecurity best practices, but the integration with older distribution systems/equipment and interconnected DER will need careful evaluation of cyber exposure.

4.5.4 Technology/Service Deployment Options

Development of a modern grid raises questions about who may provide the most cost-effective technology needed including alternatives to traditional utility capital investment. These technology alternatives related to grid modernization might include software-as-a-service, cloud-based computing, leasing telecommunications, and leveraging Energy Services Providers (ESP) and/or third- party investments. This does not include utility infrastructure upgrades that may be avoided or deferred through treatment of DER as non-wires alternatives. When choosing its path, a utility must develop a full and accurate understanding of each alternative's ability to support the required functions. The following sections discuss the alternatives at a high level.

4.5.4.1 Utility Capital Investment

Traditional investment in distribution infrastructure and modernization (e.g., smart grid) is done largely through utility capital investment. This is the current approach for advanced technologies that are part of the physical electric distribution grid, such as advanced switches. This also extends to any technologies that require direct connection to a distribution feeder, such as fault current indicators. Capital investment may also make the most sense for long-lived assets due to their long depreciation periods and lower potential rate impacts when compared with short-lived assets, such as software, or the operational expenses under an outsourced services arrangement.

4.5.4.2 Utility Outsource

Technologies supporting modern grid functions can be provided through outsourced solutions, such as software-as-a-service and cloud computing, which are commonly treated as a utility operating expense. Since outsourcing arrangements are often priced per user or device, this approach might make sense so long as the scale of the implementation is relatively small in relation to the utility's cost to license and implement its own system. However, when the ultimate scale of implementation is very large and reached quickly, the rate impact of outsourcing could be higher than if the utility had implemented the system as a capital investment.

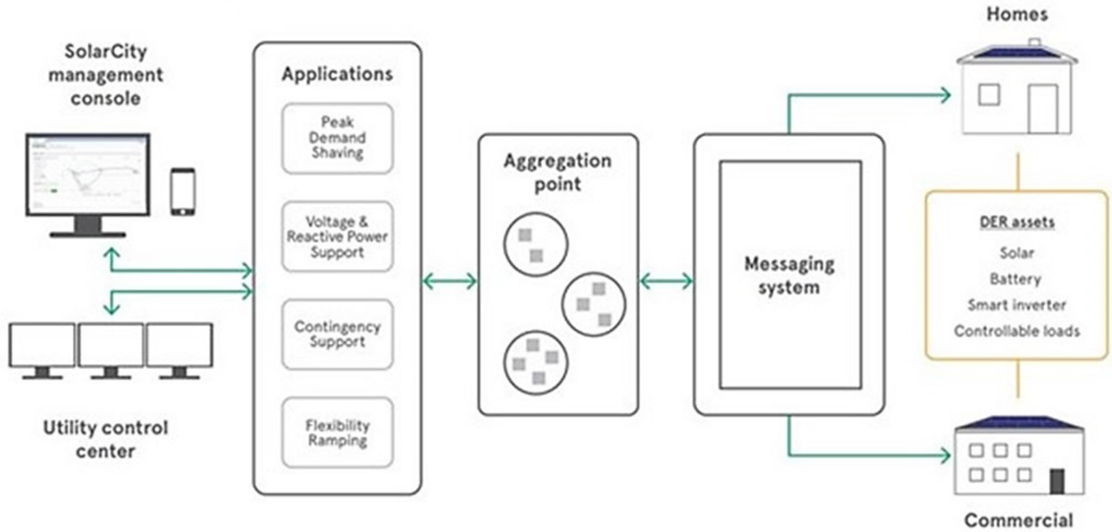
System outsourcing can mitigate some technological advancement risk since it is typical for the service vendor to periodically upgrade the outsourced system as part of the service, though this is not without a cost.

System outsourcing is increasingly being considered as a suitable alternative for non-critical utility applications. However, cybersecurity issues will vary for each type of grid system function. For example, critical operational functions like SCADA and DERMS will require greater cybersecurity evaluation when considering outsourcing to a cloud service. Nevertheless, with appropriately rigorous provisions for cybersecurity, outsourced systems can perform critical operational functions.

4.5.4.3 Energy Services Providers/Third Party Provided Functions

Utilities may be able to reduce costs by using the capabilities of technologies deployed by Energy Service Providers (ESPs) and/or third parties. Efforts to understand those capabilities and their potential uses are underway. In general, ESPs and other third parties are deploying and/or aggregating DERs that have built-in sensing, measurement, control, and communications capabilities. For example, devices installed at customer premises typically connect to the customers' onsite Ethernet or Wi-Fi communications and communicate with the ESP/third party back-end device management, data management, and control systems through the customers' internet service provider (e.g., cable, wireline, or mobile wireless). The level of cybersecurity with these systems is unclear and must be addressed, given the increasing role these resources are playing in the power system. A typical arrangement is illustrated in the Tesla graphic in **Figure 66** below.

Figure 66. Tesla DER Aggregation Architecture

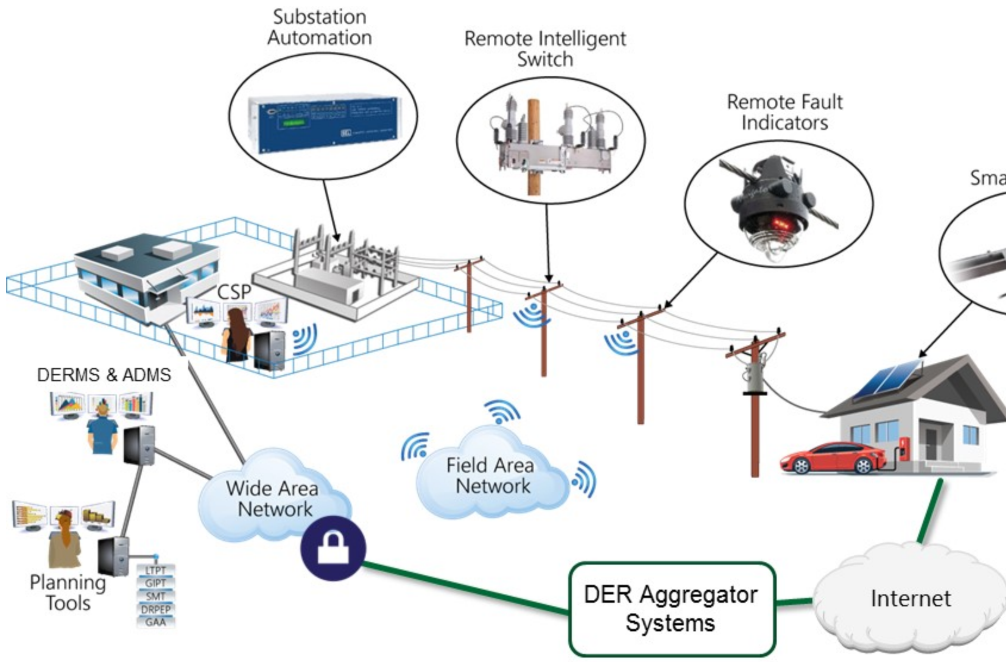


Source: Tesla/SolarCity

Some ESP/third-party capabilities might provide alternatives to utility capital expenditures, but there are important considerations. First, the ESP/third-party system manages and operates DERs that are specific to the ESP/third-party and does not interact with any part of the grid itself (such as distribution grid sensors, equipment controls, or switches). Instead, this system can potentially provide services to a grid and/or bulk power system operator by controlling and acquiring data from its affiliated DERs with a secure interface with the utility control center at the cloud interface, as shown above in **Figure 66**. ESP/third-party communication pathway through the internet and over a customer's on-premises network connection is not able to communicate with grid field switches or other grid devices (which are not connected to the internet for very good reasons). This may be obvious, but there have been extensive discussions about this very issue over the past couple of years. The ESP's assets are not a substitute for the utility's grid sensing, communications, and control systems; an adequate level of coordination between these entities is required.

Second, ESP/third-party systems might provide alternatives for DER sensing and by extension support situational awareness, as highlighted in the ISO/RTO Council's report.[81] For example, access to this information could alleviate the need for utility investment in grid edge sensors for monitoring DER performance. Third, an ESP's control system that directly controls DERs might eliminate the bulk power and/or distribution operator's need for direct DER control. Instead, utility grid control systems (e.g., DERMS) would interface with the several ESPs expected for a viable market as illustrated in the figure above. Further, ESPs' systems could reduce or eliminate a utility's need for systems and processes supporting DER, including inverter device and associated communications management. **Figure 67** below illustrates the holistic and complementary approach suggested by the Tesla system diagram above. In this closed loop system, the DER and/or ESP's system provides feedback to the operator to optimize and control grid equipment in response to changes in the distribution system that are impacted from both participating DERs and traditional loads that aggregate to the distribution circuit.

Figure 67. Complementary ESP-Grid Operator Architecture



Adapted from Southern California Edison

It is important to remember that not all customer DER will be aggregated and will still need to have a level of visibility to the grid operator. Also, more than one ESP will likely exist in a jurisdictional area and customers are likely to change ESP providers often, as has been seen in retail energy services. This means the operational coordination with ESPs will need to be standardized, as will the DER (including inverters) communication and information protocols. This may be done through market participation rules and/or interconnection standards.

4.5.5 Cost Estimating

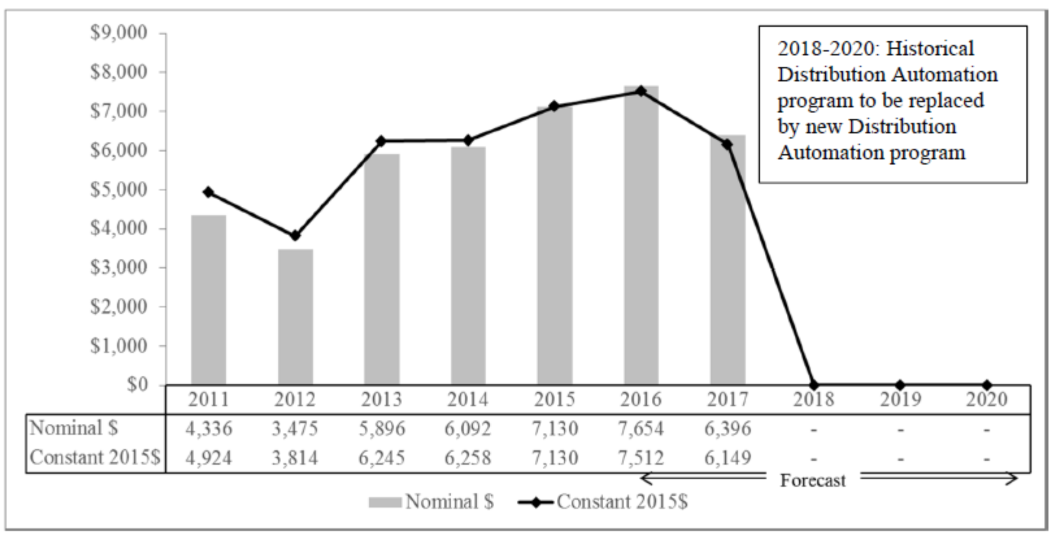
A final step in developing a deployment plan is performing a cost-effectiveness evaluation that will shape the timing, scope, and scale of a final plan. The subject of grid modernization cost-effectiveness is sufficiently complex and discussed in Chapter 5: Grid Modernization Investment Economics. The methods and approach to develop grid modernization implementation cost estimates is provided here.

Developing a detailed cost estimate starts with the implementation activities identified as part of developing the WBS along with the detailed design and related technologies. This detailed bottom-up estimate is also called an “engineering estimate.” Engineering estimates involve estimating the cost for each of the major activities within the WBS. Each major activity estimate will include individual technologies and equipment, each of which is costed separately for direct labor, direct material, and other costs. Engineering estimates for direct labor hours may be based on analyses of engineering drawings and contractor/consultant estimates or industry-wide standards. Engineering estimates for technologies and equipment are usually based on competitive vendor procurements and/or negotiated prices (e.g., for electrical equipment such as automated switches). The remaining elements of cost (such as various overhead charges) may be factored from the direct labor and material costs. The use of engineering estimates requires detailed system engineering, including the selection of specific technologies/equipment and related implementation details (e.g., timing, resources). Estimates should also include a rational project contingency based on a determination of efforts to mitigate potential project risks.

This estimation approach is closely related to the activity sequencing described above and is a complex effort for most grid modernization projects/programs. It requires a good knowledge of the activity and a reasonable level of definition for the estimate to be meaningful. Cost estimate summaries are typically provided in regulatory filings with detailed cost estimate analysis; these are available in work papers that may be treated as confidential due to sensitive vendor information. For example, distribution circuit automation estimate presented in Southern California Edison's 2018 General Rate Case[82] is summarized in **Figure 68** below, with details at the WBS activity level (referred to as "elements") provided in a companion work paper.[83]

Figure 68. SCE 2018 GRC Distribution Circuit Automation Estimate

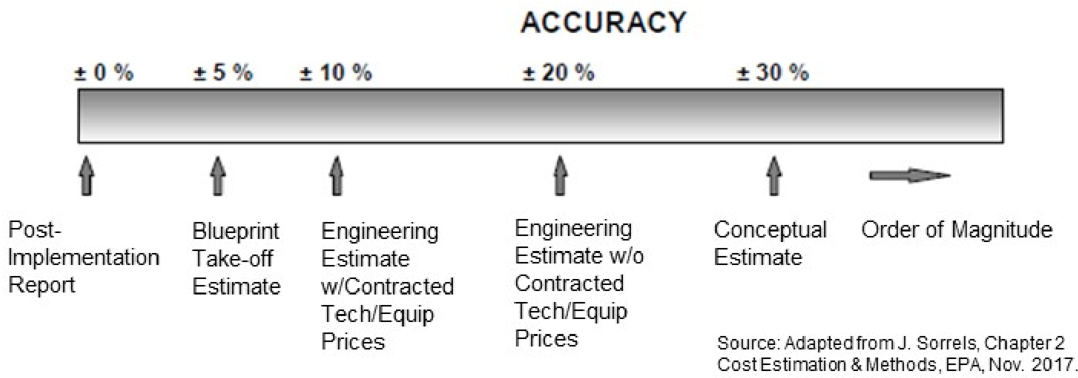
Circuit Automation[62]
Recorded 2011-2015/Forecast 2016-2020
WBS Elements CET-PD-OT-CI, CIT-00-OP-NS
(CPUC-Jurisdictional – Constant 2015 and Nominal $000)



	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Nominal $	4,336	3,475	5,896	6,092	7,130	7,654	6,396	-	-	-
Constant 2015$	4,924	3,814	6,245	6,258	7,130	7,512	6,149	-	-	-

The resulting estimates for grid modernization implementation plans will be more accurate if the technology/equipment costs are based on contracted prices and mature technologies are being deployed. Immature technologies will increase uncertainty and result in less accuracy and potential for cost overruns and schedule delays. The engineering estimate is often developed as part of preliminary engineering activity depending on the specific regulatory accounting rules and the nature of the project. Essentially, as more information is known and project risks are reduced, the cost estimate accuracy improves, as illustrated in **Figure 69**.

Figure 69. Accuracy of Cost Estimating Methods



These cost estimates are used for both refining an implementation schedule to address potential internal budget constraints and customer rate impacts as well as input for the cost effectiveness analysis discussed in Chapter 5. The sequencing of activities discussed above will incorporate cost considerations and will need to be considered to assess annual capital and operational budget impacts for any particular year in a multi-year plan. This financial impact analysis will also consider the effect on revenue requirements and related customer rate/bill impacts. Any undesirable impacts may be mitigated with adjustments to the activity sequence in terms of timing and adjusting dependencies where changes will not create unacceptable/unmanageable project risks (e.g., cost overruns and/or schedule delays).

5. Methodology to Evaluate the Cost-Effectiveness of Investments

5.1 Chapter Summary

This chapter builds on and refines the cost-effectiveness framework introduced in Volume III of the DSPx Grid Modernization Planning series. It describes a targeted framework for economic evaluation, whereby utilities and regulators categorize investments, use appropriate methods to evaluate various types of investments, and learn how to manage the risks associated with grid modernization investments.

CHAPTER OUTLINE

KEY POINTS

This chapter includes a discussion on:

- Categorizing investments based on objectives, drivers, and alignment with planning processes
- A cost-effectiveness framework that presents three economic evaluation methods (i.e., the rationale for applying best-fit most-reasonable cost, benefit-cost, and self-supporting evaluation approaches) that are applied to various categories of grid investments
- Considerations for undertaking risk-based prioritization of investments
- A conceptual application of the cost-effectiveness framework and risk-based prioritization concepts in the formulation of near- and long-term grid modernization plans

5.2 Challenges to Achieving Grid Modernization

There is broad consensus on the vision of a future distribution grid that is information-rich, flexible, automated, secure, and resilient. However, there is less consensus on the prioritization, timing, cost-effectiveness, and cost allocation of investments to achieve that vision. This chapter aims to inform approaches to evaluating the economics of grid modernization investments, as well as inform strategies for prioritizing investments building on the process and methods discussed in the prior chapters.

Utilities have traditionally had the burden of proof for demonstrating that distribution system investments are lowest reasonable cost and result in just and reasonable rates, either by demonstrating that investments are part of most-reasonable cost compliance with reliability and safety standards or by demonstrating that investments provide net benefits to customers.

Grid modernization investments create multiple challenges for this traditional paradigm. These investments may support different policy objectives and may have multiple benefits that are difficult to disaggregate and may be difficult to quantify. Additionally, the platform components of a modern grid are interdependent, requiring a minimum level of investment to create certain platform functionality. For example, a communications network deployed without field sensing and measurement devices and back-end analytic and data management systems may not create benefits until those capabilities are developed. Core investments may also require multiple years to deploy and need more than one funding application to yield desired capabilities, leading to short-term increases in costs and rates. These challenges were recognized by the California commission.[84]

Uncertainties in technology performance, cost, and need also pose a challenge for evaluating the economics of grid modernization investments. Innovation, flexibility, learning, and adaptation should thus be important principles for grid modernization investment planning; however, traditional approaches to planning and evaluating utility distribution system investments often place insufficient emphasis on risk and optionality. To address these challenges, regulators and utilities have identified the need for a general framework for evaluating the economics of grid modernization investments, referred to in this chapter as an "economic evaluation framework."

5.3 Objective-Driven and Planning-Aligned Investment

Grid modernization objectives and planning are the cornerstone of an economic evaluation framework for grid modernization investments. Objectives provide the link between investments and their expected benefits and can help regulators and utilities prioritize them as well. Utilities have long used planning and supporting tools to evaluate and justify spending.

Different jurisdictions will identify and emphasize different objectives for modernizing their distribution grids, which will then shape their economic evaluation approaches.

> **"There are challenges to establishing a method to evaluate the cost effectiveness of grid modernization requests related to DER integration. Grid modernization investments can span a portfolio of interrelated distribution expenditures that simultaneously support DER integration and ensure safety and reliability."**
> **- California Public Utilities Commission**

85

For instance, some jurisdictions may treat AMI as a core investment borne by all ratepayers to further objectives for time-varying rates, customer choice, reliability improvements, and/or DER integration. In other jurisdictions, AMI may be coupled with a shift to time-varying rates and subject to benefit-cost analysis or paid for by customers participating in opt-in utility programs.

Jurisdictions' priorities among different objectives will also shape investment priorities, for example:

- A jurisdiction that prioritizes customer choice may choose to prioritize investments in AMI technologies including smart meters, telecommunications, and customer portals.

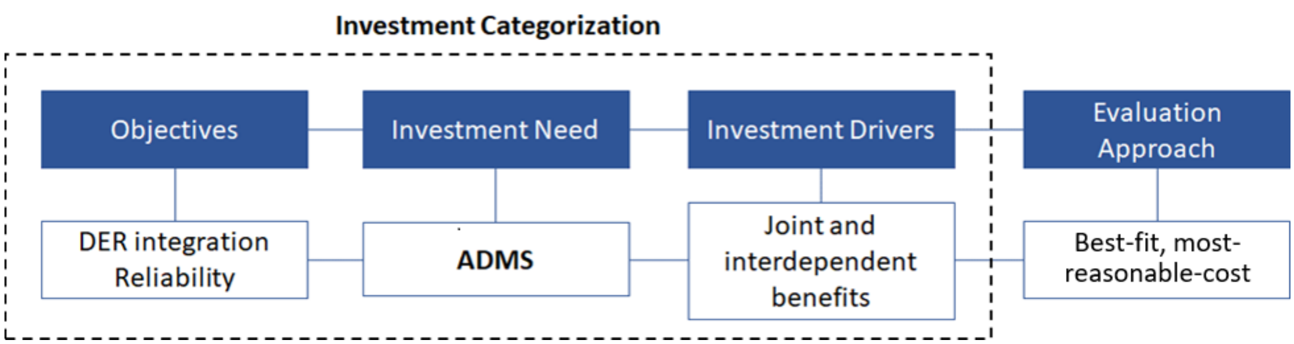
- A jurisdiction that prioritizes DER integration may choose to prioritize distribution monitoring, sensing, and control systems that enable higher penetrations of distributed generation and energy storage.
- A jurisdiction that prioritizes reliability may prioritize distribution automation and outage management systems.

As discussed in Chapter 2, grid modernization is driven by ongoing utility planning processes, which may include distribution capacity planning, reliability and resiliency planning, integrated resource planning, program planning, DER planning, and transmission planning. The extent to which utilities are responsible for resource, program, and DER planning will also vary across jurisdictions and industry structures, with implications for economic evaluation frameworks. For instance, planning processes and evaluation frameworks for vertically integrated utilities will be very different from "wires-only" utilities.

This chapter describes a targeted framework for economic evaluation whereby investment needs are identified, linked to objectives, and categorized by investment drivers through grid modernization planning. As described in more detail in the next section, investment drivers include joint and interdependent benefits, standards compliance, policy mandates, customer net benefits, and customer choice.[xxix]

Different drivers have different approaches to economic evaluation. **Figure 70** provides a simple illustration of this investment categorization process and its links to economic evaluation methods.

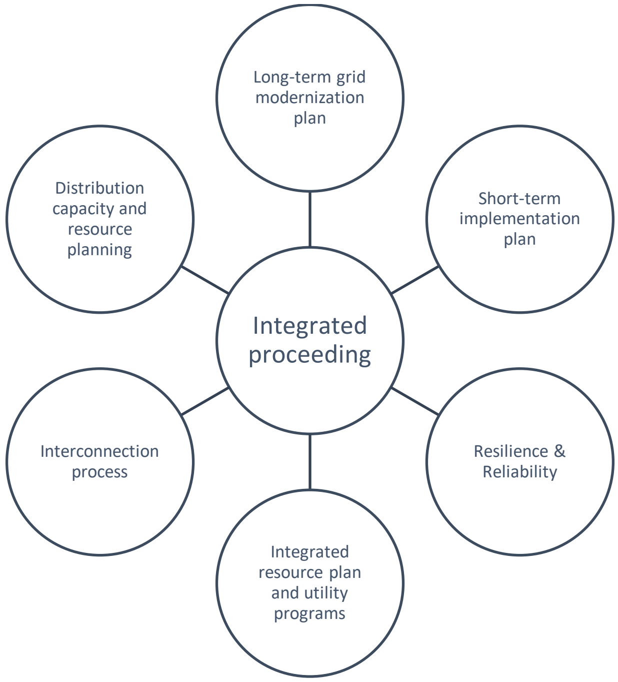
Figure 70. Illustration of Investment Categorization by Objectives, Drivers, and Economic Evaluation Approach



Categorizing investments for economic evaluation requires coordination among planning processes, including those in which grid modernization investments are reviewed and approved, to avoid double counting and to support a holistic approach to distribution system investment, as shown in **Figure 71**. As discussed above, for example, ensuring that investments remain consistent with long-term objectives over time requires coordination between a longer-term strategic plan and shorter-term implementation planning.

[xxix] Customer choice here means providing customers the ability to apply a broad set of energy management and generation options, including utility investments triggered by customer interconnection, opt-in utility programs, and reliability improvements, all paid for by individual customers.

Figure 71. Illustration of the Need for a Regulatory Proceeding to Integrate Different Planning Processes



Efforts in California and Massachusetts provide examples of two approaches to planning process coordination. The California Public Utilities Commission (CPUC) ordered utilities to develop grid modernization plans that included 10-year grid modernization visions and used information from their distribution resource plans to support the drivers and rationale for grid modernization investments in general rate case filings.[86] The Massachusetts Department of Public Utilities (DPU) required utilities to develop and regularly update 10-year grid modernization plans as well as develop initial 5-year short-term investment plans (STIPs), with investments in the STIPs eligible for pre-authorization.[87]

Designing economic evaluation frameworks around jurisdiction-specific objectives, priorities, and planning processes can help to ensure that investment strategies are consistent with and promote priority objectives, and that grid modernization planning is well-integrated with other existing utility planning activities. Objective-driven investments that are also aligned with other plans can also help to promote transparency, fair and efficient cost allocation, learning, and adaptation. Planning in this way will help answer the following questions:

- What benefits should investments deliver?
- How should beneficiaries pay for them?
- Did they perform as expected? If not, how can investment strategies and plans be adjusted to improve performance?

A key benefit of implementing objective-driven and aligned planning processes is the ability to evaluate investments based on objective-specific performance metrics and to adapt long-term strategy and short-term implementation plans based on performance. For instance, an ADMS that is primarily intended to improve reliability and enhance DER integration can be evaluated based on its impact on outage metrics and DER-specific metrics, such as interconnection costs or hosting capacity for distributed generation. Implementation and performance metrics can be set through grid modernization plans and evaluated through regular assessment. As discussed throughout the document, mapping investments back to objectives is necessary to convey the logic for deploying technologies and the benefits they provide.

5.4 Cost-Effectiveness Framework

Because of the diversity of grid modernization objectives and investments, there is no single standard or method for determining the cost-effectiveness or prudence of grid modernization investments. Instead, economic evaluation approaches can be designed around different objectives and needs to better match investments with their expected benefits. Each jurisdiction's approach will differ due to different objectives, priorities, spending limits, cost allocation principles, and industry structure.

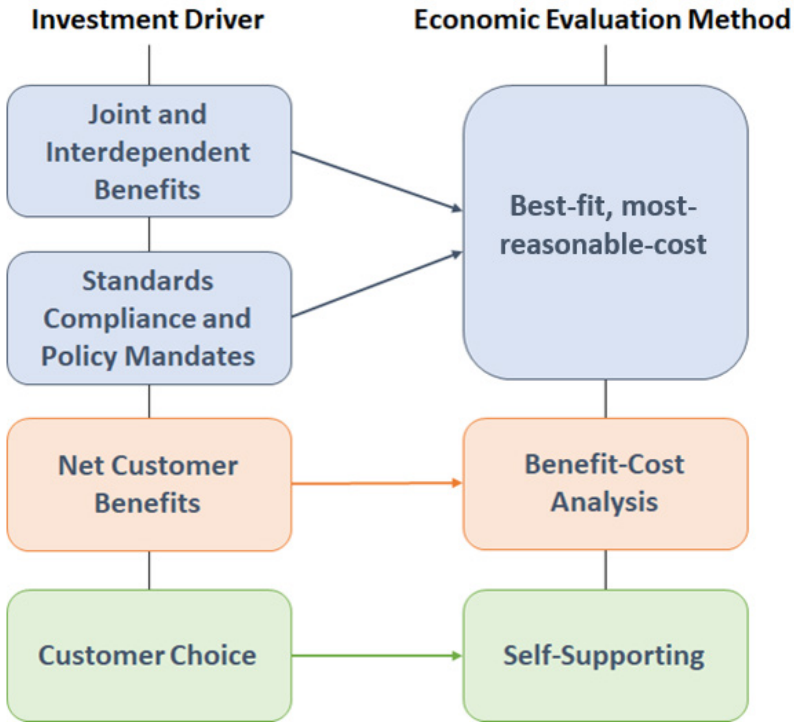
A cost-effectiveness framework should recognize that utilities have historically used different methods for evaluating different kinds of investments. For grid modernization, economic evaluation methods are specific to the reason, or driver, for investment needed. There are four main reasons for initiative grid modernization investments:

1. *Joint and interdependent benefits* — core platform investments that are needed to enable new capabilities and functions in the distribution grid
2. *Standards compliance and policy mandates* — utility investments that are needed to comply with safety and reliability standards or to meet policy mandates for proactive investments to integrate DER or resilience objectives
3. *Net customer benefits* — utility investments from which some or all customers receive net benefits in the form of bill savings
4. *Customer choice* — utility investments triggered by customer interconnection, opt-in utility programs, and customer-driven reliability improvements, paid for by individual customers

In the cost-effectiveness framework proposed in this guidebook, investments that provide joint and interdependent benefits or facilitate compliance with standards and policy mandates are subject to a best-fit, most-reasonable cost standard, which indicates that an investment provides the highest value for a reasonable cost with respect to meeting objectives. Investments that are expected to provide net customer benefits are subject to ex-ante[xxx] benefit-cost analysis. In this case, a portfolio of investments is deemed cost-effective if its lifecycle benefits exceed its lifecycle costs, and thus the portfolio may be approved or deemed prudent by regulators. Investments that are paid for by customers are "self-supporting" because they are assumed to be cost-effective (see **Figure 72**).

[xxx] "Ex-ante" means "before the event" and applies to analytical findings based on forecasts rather than actual results.

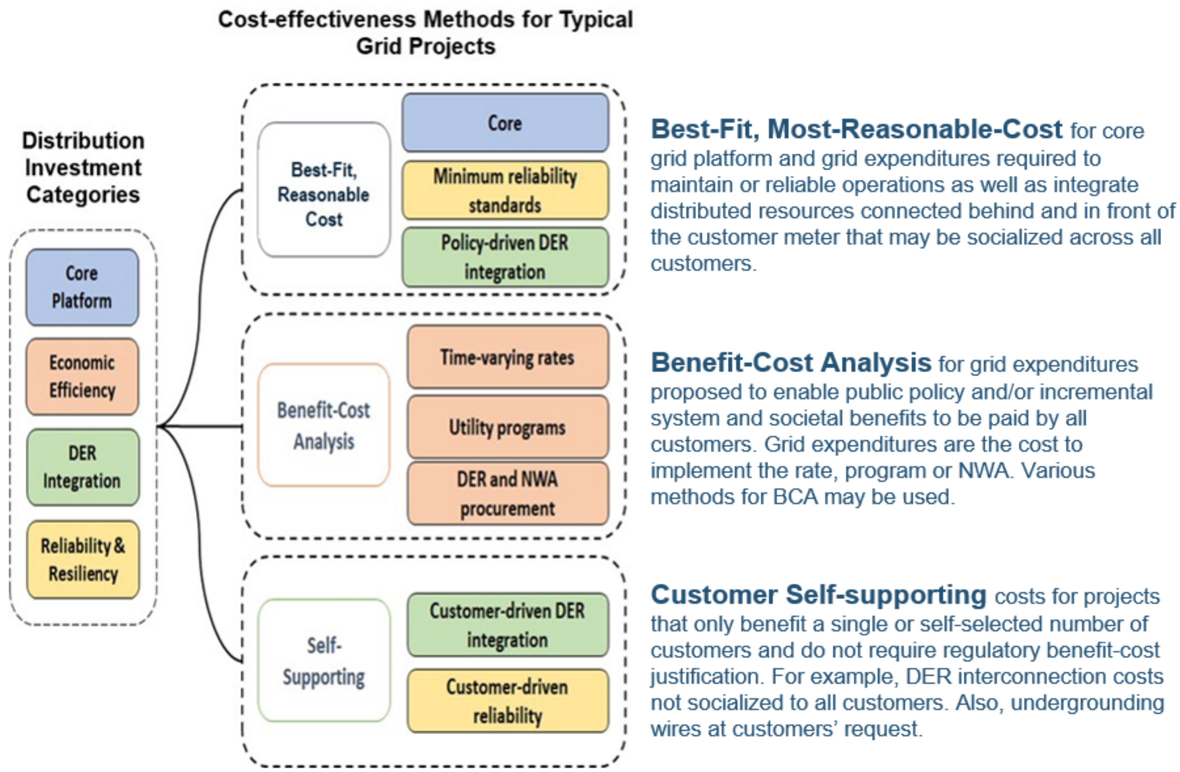
Figure 72. Investment Drivers and Their Economic Evaluation Methods



Using targeted methods to evaluate different investments will require categorizing potential investments. Utilities and regulators may first determine the kinds of investments that should be treated as core investments, as illustrated in Chapter 3 (see Figure 34. Technology Stack on page 60). After identifying core investments, utilities and regulators can then categorize other investments (**applications**) by objectives and drivers to determine how they should be evaluated. Regulators can also simplify this process by just using the core and application categories while requiring utilities to demonstrate best-fit, most reasonable cost for core investments and use benefit-cost analysis for application investments, assuming that all other grid modernization investments will be self-supporting.

Figure 73 shows an illustrative categorization of different kinds of grid modernization investments by objectives and economic evaluation methods. Grid investments are grouped into four high-level, categories of investments: core platform, economic efficiency, DER integration, and reliability and resiliency. These categories cover investments related to both core components and applications; together they support a variety of utility and customer-based activities. The categorization in the figure is illustrative—different jurisdictions will have different objectives and organize investments into different activity groupings.

Figure 73. Illustrative Categorization of Objectives, Economic Evaluation Methods, and Activities for Grid Modernization Investments



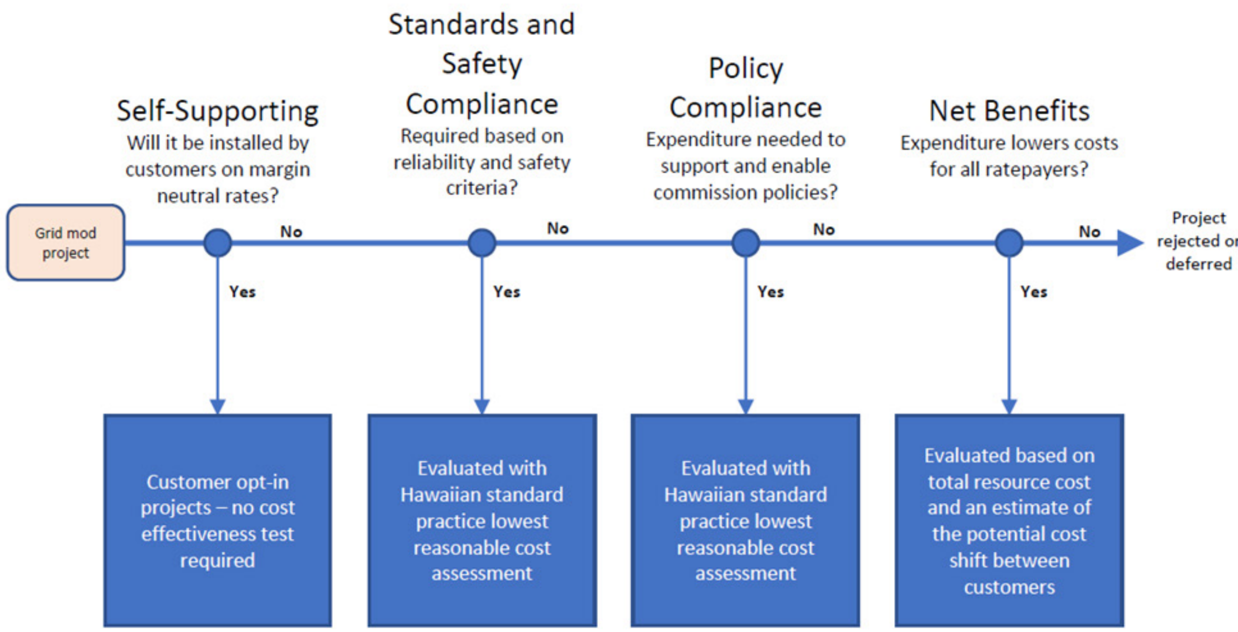
The above figure demonstrates that although grid modernization investments contribute to the same objective, they may have different investment drivers and evaluation methods and may be "triggered" through different processes. For instance, regulators may direct utilities to make some proactive core investments to support DER adoption and utilization (policy-driven DER integration), whereas related non-core investments would be evaluated through utility procurements (e.g., DER and NWA procurement) or triggered by and paid for by customers through the interconnection process. Furthermore, an application (e.g., smart meters) may support multiple objectives and represent a variety of investment categories (e.g., economic efficiency, DER integration, reliability and resiliency) and drivers (e.g., time-varying rates, minimum reliability standards, policy-driven DER integration).

Approaches to categorizing investments will vary across jurisdictions, particularly for grid modernization investments to support DER. Policymakers and regulators in some jurisdictions will direct utilities to proactively invest in the grid to prepare for DER adoption (policy-driven DER integration), whereas regulators in other jurisdictions may require utilities to demonstrate that grid modernization investments that support DER are cost-effective for ratepayers. In yet other jurisdictions, regulators may work to ensure margin-neutral rates[xxxi] for DERs, which require DER customers to pay for any incremental grid costs associated with DER interconnection and operation.

[xxxi] Margin-neutral rates occur when the bill reduction for a DER participant is not greater that the costs the utility avoids from the grid services that the DER participant provides. "Margin-neutral rates leave the utility with the same margin regardless of the customers' usage, where 'margin' is defined as the revenue above the variable costs that contributes to the utility's recovery of its fixed costs." Definition from: Hawaiian Electric, *Modernizing Hawai'i's Grid For Our Customers*, August 28, 2017, p. 47.

Decision trees can be a useful tool for helping to categorize investments and determine whether they are needed. **Figure 74** shows an example decision tree from the net benefits assessment in the Hawaiian Electric Companies' *Grid Modernization Strategy*.[88] The specifics of these kinds of decision trees, both in their level of detail and in the ordering of their investment drivers, will vary across jurisdictions.

Figure 74. Illustrative Decision Tree for Evaluating Grid Modernization Investments



Using different methods to evaluate different kinds of grid modernization investments provides a cost-effectiveness standard for all investments and serves as a more practical alternative to using only a benefit-cost analysis. Matching investments and evaluation methods can improve the transparency and effectiveness of grid modernization investments by linking investments to their expected benefits and providing an analytical and procedural foundation that facilitates review, learning, and adaptation. It also allows different investments to be triggered at different times based on priorities and needs according to approved plans and sequencing strategies, as described in Chapter 4 of this Guidebook.

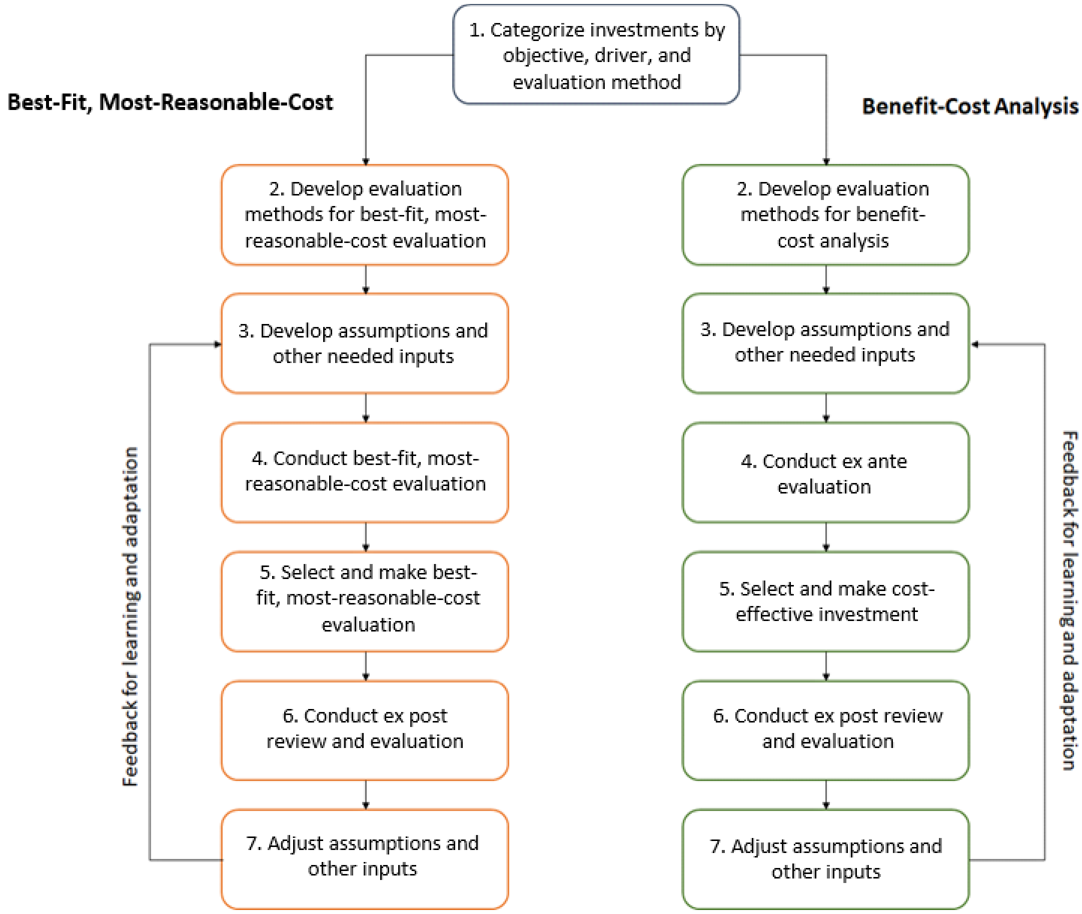
This targeted approach to evaluating grid modernization investments does not preclude an overall benefit-cost analysis for a grid modernization plan, which could be included as part of a long-term strategic plan.[89] In this case, the use of such a benefit-cost analysis would be mainly to inform strategy and priorities (e.g., to determine if a policy would provide a net benefit to utility customers). This Guidebook refers specifically to grid investments that are already informed by policies.

Although best-fit most-reasonable cost and benefit-cost analysis methods differ in their specifics, they share the same evaluation process (**Figure 75**) where learning and adaptation are facilitated by the feedback provided by ex-post evaluation[xxxii] based on predetermined implementation (infrastructure) metrics and performance metrics. An implementation metric might include the extent of distribution

[xxxii] "Ex-post" means "after the event" and applies to analytical findings based on examining results after they have occurred.

system automation, whereas a corresponding performance metric would be a measure of outage impacts.[xxxiii]

Figure 75. Economic Evaluation Process for Best-Fit, Most-Reasonable-Cost Evaluation and Benefit-Cost Analysis



Sections 5.4.1 and 5.4.2 describe methods for evaluating investments that fall under a best-fit most-reasonable cost and benefit-cost rubrics, respectively. Section 5.4.3 describes a framework for defining the scope and allocation of costs associated with self-supported investments.

5.4.1 Best-Fit, Most-Reasonable Cost Evaluation

This section describes evaluation methods for three kinds of grid modernization investments that may fall within a best-fit most-reasonable rubric: core investments, investments to comply with minimum reliability standards, and investments to comply with policy mandates to proactively integrate DER. These three categories are illustrative; not all jurisdictions will have policy mandates for DER integration, for instance, in which case grid investments to support higher DER penetration may require benefit-cost analysis or be supported by customers.

[xxxiii] An illustrative list of potential metrics for meeting grid modernization goals can be found in the Massachusetts Department of Public Utilities' straw proposal (2014) for performance metrics. Efforts to finalize performance metrics were ongoing at the time of writing. For the DPU's list of metrics, see: Massachusetts Department of Public Utilities, "Investigation by the Department of Public Utilities on its own Motion into Modernization of the Electric Grid," D.P.U. 12-76-B, 2014, pp. 31-32.

5.4.1.1 Core Investments

Core investments enable other investments and have joint benefits that will often increase as more capabilities and functions are added to the distribution system.

A traditional benefit-cost analysis is not well-suited for evaluating core investments. This analysis is most meaningful when investments have benefits and costs that are discrete, clearly attributable to individual investments, and marginal—i.e., costs do not increase or decrease depending on utilization. Core investments have joint costs and joint interdependent benefits that are shared across multiple objectives and customers, and their benefits and costs are often not marginal. For instance, the cost-effectiveness of investments in communications infrastructure for the distribution system will depend on the extent of its use in delivering cost savings and reliability benefits, as well as enable additional functionality.

Long-term strategic planning can identify core investments based on desired capabilities and functionality (or "best fit"), and utilities can use competitive solicitations to procure these investments. Utilities have the burden of proof for demonstrating most-reasonable-cost procurement, based on commission guidelines.

In many cases, core investments will account for the majority of grid modernization investments and, as a result, the desired level of core investment may exceed a jurisdiction's budget threshold. In these cases, core investments can be sequenced based on priorities and spread out over time (Section 5.5). Investments can also be timed to align with depreciation cycles, allowing greater headroom in rates. As a result of different objectives and priorities, both the scope and the sequencing of core investments will vary across jurisdictions and utilities.

> **"To determine the cost effectiveness of each grid modernization investment, the IOUs would need to identify the driver of the investment and isolate the value of its contribution to enabling DER growth. We find this infeasible, given the multiple, interrelated functions of grid modernization investments."**
>
> **- California PUC, Decision 18-03-023**

Although individual core investments may be subject to best-fit, most-reasonable cost evaluation rather than ex-ante benefit-cost analysis, they should also be subject to regular ex-post assessments based on predetermined performance metrics. An ex-post assessment can be timed to correspond with planning and investment cycles.

An ex-post assessment provides important feedback that enables learning and adaptation and ensures that investments are in ratepayers' and the public's interest—for example, to determine if individual investments performed as expected and provided expected benefits. Rather than retroactive prudency determinations, an ex-post assessment can focus on "prospective prudency,"[90] done with an eye to informing and adapting the next round of investments, and implementation prudency. An example of the latter is in Massachusetts, where regulators allowed utilities to obtain pre-authorization for grid modernization investments included in STIPs and limited prudency review to investment implementation rather than whether utilities should have made the investments.[91]

5.4.1.2 Minimum Reliability Standards

A minimum reliability standard for distribution utilities is a requirement to meet a distribution system-wide minimum performance standard for reliable service, based on traditional distribution system reliability metrics: SAIDI, SAIFI, CAIDI, and customer average interruption frequency index (CAIFI).

A system-wide minimum reliability standard requires all parts of the distribution system to meet the minimum standard. This differs from a system-wide reliability standard, where utilities are required to maintain average levels of reliability. Investments to maintain system reliability standards would likely be part of utilities' conventional distribution planning, whereas investments to achieve minimum reliability standards could be included under grid modernization planning because meeting minimum standards would likely require advanced functional capabilities.

Minimum reliability standards may be set on the basis of benefit-cost analysis. For instance, utilities may recommend a standard to a commission based on studies that weigh the incremental benefits of reduced customer outages against the incremental investment and operating costs needed to achieve a given standard. However, once the standard is set, utilities would use a best-fit most-reasonable cost approach to comply.

Beyond the minimum standard, customers can choose to invest in technologies and infrastructure that provide higher levels of reliability and resilience, such as customer-sited energy storage, microgrids, and infrastructure hardening. However, the incremental costs of reliability improvements beyond the minimum standard would be directly assigned to those customers (Section 5.4.3).

This same minimum standards-based approach to reliability can also be extended to resiliency. For instance, state legislators, working with utilities and regulators, could set a target for minimum restoration times after extreme weather events. The resiliency goal could be based on benefit-cost analysis, but utilities would comply with the goal using a best-fit most reasonable approach.

5.4.1.3 Policy-Driven DER Integration

Autonomous DER adoption—adoption of DER by customers outside of utility programs, resource procurement, and non-wires procurement—may require larger-scale distribution software and hardware investments to ensure that the distribution system can operate reliably and efficiently use DER.

To promote customer choice, competition, and environmental goals, regulators may direct utilities to plan for and make some of these investments proactively, rather than having them be triggered through utility procurement planning or the interconnection process. These investments would be subject to best-fit most reasonable evaluation instead of benefit-cost analysis.

If investments to support DER are evaluated through best-fit most reasonable cost approach, a needs assessment becomes an essential step in identifying the grid technologies needed to support reliable, safe, and economic operation of DER at different levels of penetration. A needs assessment may involve an iterative process between regulators and utilities. For instance, in California, the CPUC authored a *Staff White Paper on Grid Modernization* that developed a framework for classifying grid needs and potential investments for DER integration and proposed a process for authorizing investments.[92] The CPUC then directed utilities to propose and justify specific investments in their grid modernization plans, which were informed by their distribution resource plans.[93]

In long-term strategic plans, utilities and regulators can set performance metrics for investments to support policy-driven DER integration along with an ex-post assessment. The performance assessment will help utilities and regulators determine if the pace of investment was appropriate, whether the technologies were effective, and whether adjustments to long-term strategic plans and nearer-term implementation plans are needed.

5.4.2 Benefit-Cost Analysis

Regarding the framework presented here, utilities would use benefit-cost analysis to evaluate a subset of grid modernization investments expected to provide net benefits to utility customers in the form of bill savings. Utilities have historically had the burden of proof for demonstrating that the benefits of these kinds of investments exceed the costs over the lifetime (or lifecycle) of the investments.

Although DER and rate design[xxxiv] are not grid modernization investments per se, grid modernization investments may be needed to enable higher DER penetration or support new rate designs that generate bill savings for ratepayers. If the lifecycle benefits of a DER portfolio are higher than their lifecycle costs (including the incremental cost of any needed grid modernization investments), these grid modernization investments will be deemed cost-effective and their costs may be allocated to all ratepayers or to a certain subset. Jurisdictions use different cost tests to evaluate cost-effectiveness.[94]

Benefit-cost analyses for grid modernization investments occurs in different processes and proceedings. Utilities perform a benefit-cost analysis for grid investments to support DER in planning for demand-side programs, resource procurement, and procurement of non-wires alternatives. Utilities also perform benefit-cost analyses for grid investments to support new rate designs in a variety of proceedings, ranging from rate cases to grid modernization proceedings.[xxxv] For example, where rates for DER customers are not considered to be "margin neutral"—meaning that DER generates net benefits to other utility customers that are not compensated through rates—grid investments to support DER may also be evaluated in a separate DER planning process, where a cost-benefit analysis can determine if the benefit to the utility outweighs any incremental costs to the utility.[xxxvi]

Ratemaking, utility programs, utility resource procurement, and utility non-wires procurement are often separate, standalone processes. To determine the most cost-effective grid modernization investments, utilities and regulators will need to enable coordination between ratemaking, programs, and procurement processes and various grid modernization proceedings. For instance, the incremental costs of grid modernization investments to support higher DER penetration may be developed as part of a specific grid modernization proceeding, but most of the benefits analysis to determine the cost-effectiveness of DER will take place in other processes and proceedings. Coordination can facilitate consistent assumptions and estimates across processes and further support the need to develop holistic grid modernization strategies that can support multiple efforts.

[xxxiv] As an example, the benefit-cost analysis associated with applying a time-varying rate would compare the benefits derived from applying the rate—e.g., through peak demand reduction (generation capacity reduction) or energy savings—to the costs of implementing a time-varying rate program.

[xxxv] For instance, time-varying rate designs in California have been largely considered through rate cases or dedicated rate reform proceedings; whereas in Rhode Island, time-varying rate designs are being considered through grid modernization proceedings under Docket 4600.

[xxxvi] An example is California's distribution resource planning (DRP) process.

Utilities and commissions in several jurisdictions have recently enhanced methods for calculating and expanded the scope of benefits included in benefit-cost analysis for DER and rate designs.[95] Important developments include efforts to more accurately calculate area and time-specific benefits, greater inclusion of non-energy benefits, and greater emphasis on sensitivity analysis and risk-adjusted results.

Table 3 provides a list of potential benefits that might be included in benefit-cost analysis for DER and new rate designs.[96] The shaded cells indicate benefits that may have zonal or local values.

Table 3. Potential Benefits Included in Benefit-Cost Analysis for DER and New Rate Designs

Benefit Category	Description	Locational Value
Generation capacity	Incremental value in reducing wholesale capacity costs	Zonal/local capacity market price
Energy	Incremental value in reducing wholesale energy costs	Locational marginal price (LMP) or aggregated LMP
Ancillary Services	Incremental value in reducing regulation and operating reserve costs	Zonal regulation or operating reserve prices
Market price mitigation	Incremental value in reducing the cost to consumers of high market prices	Locational marginal price (LMP) or aggregated LMP
Transmission and sub-transmission capacity	Incremental value in deferring transmission and sub-transmission investments	N/A
Transmission losses	Incremental value in reducing transmission losses	Incorporated in LMP or aggregated LMP
Distribution capacity	Incremental value in deferring distribution infrastructure investments	Based on utility estimates
Distribution O&M	Incremental value in reducing distribution O&M costs	Based on utility estimates
Distribution losses	Incremental value in reducing distribution line losses	Based on utility estimates
Customer costs	Incremental value in reducing customer costs, including labor costs for meter reading	Based on utility estimates
Net restoration costs	Incremental value in reducing the net costs of restoring power	Based on utility estimates
Net customer outage costs	Incremental value in reducing net outage costs	Based on utility estimates
CO_2 emissions	Incremental value in reducing emissions allowance costs, or based on an estimate of the social cost of carbon	N/A

Criteria pollutant emissions	Incremental value in reducing emissions allowance costs, or based on estimates of reduced health impact costs	Based on impacts of local health costs
Other non-energy benefits	May include water, land, equity, and other costs not included above	

Benefit-cost analysis for DER and rate designs should include the full range of incremental costs—including incremental metering, grid infrastructure, operating, and program costs—as shown in **Table 4**. Costs should be incremental to the minimum standards and policy compliance investments from the previous section. For instance, an evaluation that involves volt-VAR optimization (VVO) as an application would include VVO costs, but not the costs of the supporting ADMS, which would be categorized as a core investment.

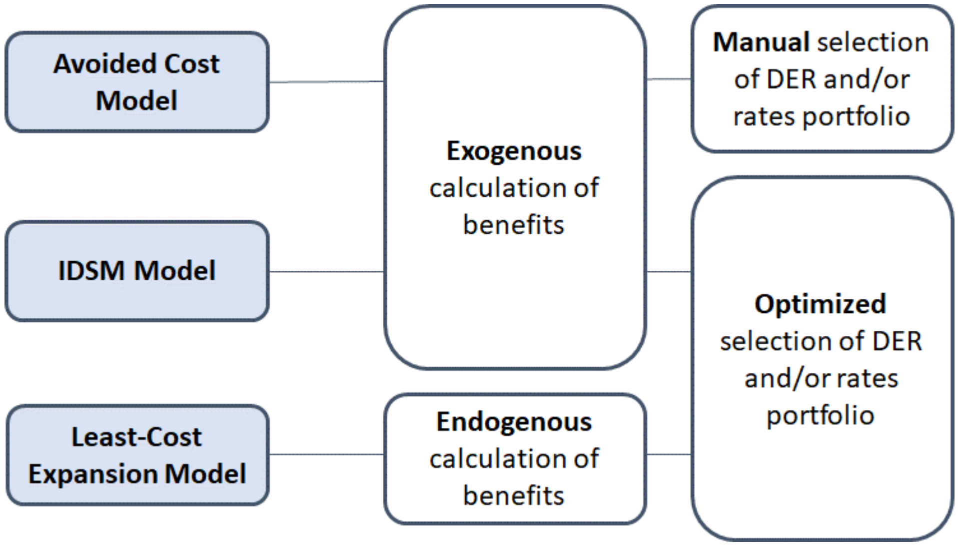
Table 4. Incremental Cost Categories and Components for DER and Rate Designs

Cost Category	Components
Resource	Incremental investments in distributed energy resources
Metering	Incremental metering and data management costs
Grid Infrastructure	Incremental distribution system hardware and software needed for capacity, monitoring, sensing, measurement, protection, control, and information management
Operating	Any increased reserve or imbalance costs[xxxvii]
Program	Program administration costs

Approaches to evaluating the cost-effectiveness of DER and rates fall into three main categories, as illustrated in **Figure 76**. Avoided-cost models exogenously[xxxviii] calculate values for some or all of the benefits in Table 3. Planners test whether the lifecycle benefits of a portfolio of DER or proposed rate designs[xxxix] exceed the lifecycle costs. For example, integrated demand-side management (IDSM) models optimally select a portfolio of DER based on a target need or budget and exogenously determined benefits. Least-cost (capacity) expansion models minimize the total discounted costs of a portfolio of DER and bulk system resources over time.

[xxxvii] If reserve costs are allocated on the basis of net load variability, higher DER penetrations could increase utilities' reserve costs. Higher DER penetrations could also increase imbalance costs, which in ISO-operated markets currently include two main components: (1) the difference between day-ahead and real-time prices, and (2) unit commitment costs. Both reserve and imbalance costs will be small to zero in the near term.
[xxxviii] "Exogenous" here refers to the fact that benefits are calculated separately from the selection of a resource portfolio.
[xxxix] For example, new rates may be designed by regulators to send appropriate price signals that motivate customers to act in ways that benefit themselves and the grid as a whole.

Figure 76. Approaches to Cost-Effectiveness Evaluation



All three modeling approaches generate results that are consistent with the cost tests that utilities have historically used to evaluate utility energy efficiency and demand response programs. In avoided-cost models, the cost-effectiveness of a specific program (or technological option) is evaluated by comparing its benefit-cost ratio against the other options within a portfolio. In IDSM and least-cost expansion models, by contrast, cost-effectiveness is determined by optimizing across a set of resources to derive a least-cost portfolio.

None of these three approaches is inherently superior; each may be better suited for different situations. Utilities have often used avoided-cost models for evaluating utility energy efficiency and demand response programs and time-varying rates. For example, utilities in New York have used IDSM models as a screening tool for non-wires procurement.[97] Utilities have also begun to include DER in least-cost expansion models used in integrated resource plans, allowing distributed generation, energy efficiency, customer-sited storage, and demand response to be treated as selectable resources in a least-cost resource portfolio.[98]

Across these different approaches, new best practices are emerging, including:[99]

- Conducting integrated analysis on a portfolio of measures rather than individual measures
- Capturing interactions among individual measures, such as distributed solar and storage
- Using scenarios and sensitivity analysis rather than point estimates
- Allowing benefits to be reasonably stacked
- Coordinating the use of distribution planning outputs—the value of distribution deferral and avoided distribution losses and incremental grid infrastructure costs—as resource planning inputs

The benefits in Table 3 can be used to set margin-neutral rates for DER customers, as in the case of New York's value of a DER (VDER) tariff.[100] In cases where DER providers are providing value to the system that is not compensated through rates, benefit-cost analysis can also be used to evaluate the cost-effectiveness of incremental grid modernization investments to support DER that are paid for by non-participants when the benefits to non-participants outweigh the costs.

Planning assumptions around the objectives and sequencing of grid modernization investments can have a significant impact on benefit-cost analysis. If an investment is justified in terms of one or more objectives, its costs may be included in the "baseline"—as an investment that has already been made—when evaluating the cost-effectiveness of other investments.

If an investment has multiple benefits and meets multiple objectives, these benefits may need to be allocated across that investment for the purposes of cost-effectiveness evaluation. For instance, consider a case in which a utility determines that distribution feeder upgrades are needed for both compliance with a reliability standard and for cost-effective DER procurement. If the feeder upgrades can be justified solely for reliability, planners would assume these investments are already in place when evaluating DER for procurement (i.e., the incremental costs of DER would not include these costs). If they cannot be justified solely for reliability, planners should subtract the incremental reliability benefits of the feeder upgrades—for instance, reduced outage energy multiplied by a value of lost load—from the incremental costs of the investments when evaluating DER for procurement.

A second example of how planning assumptions affect benefit-cost analysis involves baseline setting of load profiles for electrification. For instance, in a state that is planning for transportation and building electrification, the baseline for benefit-cost analysis of AMI should reflect "unmanaged" EV and heating loads under the assumption that loads would not be able to be shifted without AMI. Additionally, the baseline for benefit-cost analysis of distributed generation, storage, energy efficiency, and DER should also reflect assumptions about AMI and the extent to which EV and heating loads have been "managed" through time-varying incentives. These assumptions will likely have a significant effect on the cost-effectiveness of both AMI and DER. Distribution-level storage, for instance, will be significantly more cost-effective in an environment with unmanaged charging than in an environment with managed charging.

5.4.3 Self-Supporting Investments

Self-supporting grid modernization investments are driven by and paid for by customers. Two main categories of self-supporting investments include:

- Incremental investments to resolve reliability impacts associated with, and/or improve, the deliverability of customer-owned DER ("customer-driven DER integration")
- Incremental investments that are directly or indirectly necessary to improve customer reliability or resiliency ("customer-driven reliability and resiliency")

The boundaries between customer-driven and policy- or standards-driven DER and reliability are often blurred. However, because utilities may use different approaches to evaluate different categories of investments, and because of the implications for equity and fair cost allocation, clearly demarcating these boundaries is an important task within grid modernization.[xl] For example, one may need to differentiate between the following three scenarios:

[xl] For instance, the California Public Utilities Commission (CPUC) limited the scope of its grid modernization proceeding to "… investments that are triggered by the expectation of cumulative impacts of DERs in a particular area," but did not define "cumulative impacts." See: CPUC, "Decision on Track 3 Policy Issues, Sub-Track 2 (Grid Modernization)," Decision 18-03-023 (2018).

- How much of the incremental grid costs to support DER should be socialized to support policy (best-fit most-reasonable cost evaluation)
- How much should be paid for by non-participating customers that benefit from DER (benefit-cost analysis)
- How much should be paid for by interconnecting customers (self-supporting)

Customer-driven investments to support DER integration are often triggered by interconnection requests. Many states have upgraded interconnection rules and processes to respond to increases in distributed PV adoption. Interconnection improvements include: streamlined interconnection processes, greater transparency and certainty on interconnection costs, and requiring utilities to analyze and publish hosting capacity.[101] In addition, growth in distribution-level storage and electric vehicle charging will require continued enhancements in interconnection policies and greater clarity on how incremental grid costs are allocated.

Cost-sharing issues between the utility and its customers for grid investments triggered in the interconnection process are complex, requiring clear principles and rules. For instance, one may question if a customer installing a relatively small PV system would be charged for the full cost of a substation upgrade if that customer's PV system happens to trigger the upgrade. Emerging approaches to dealing with this challenge include: [102]

1. *Post-upgrade reimbursement*, where the initial interconnecting project pays the full upgrade amount but is later reimbursed by later projects that benefitted from the upgrade
2. *Preemptive upgrades*, where utilities preemptively identify and make upgrades and charge the cost of the upgrade as a fee to interconnecting customers that benefit from it
3. *Flexible interconnection*, where utilities reserve the right to curtail interconnecting projects as needed but not do not make or charge projects for upgrades

5.5 Risk-Based Prioritization of Investments

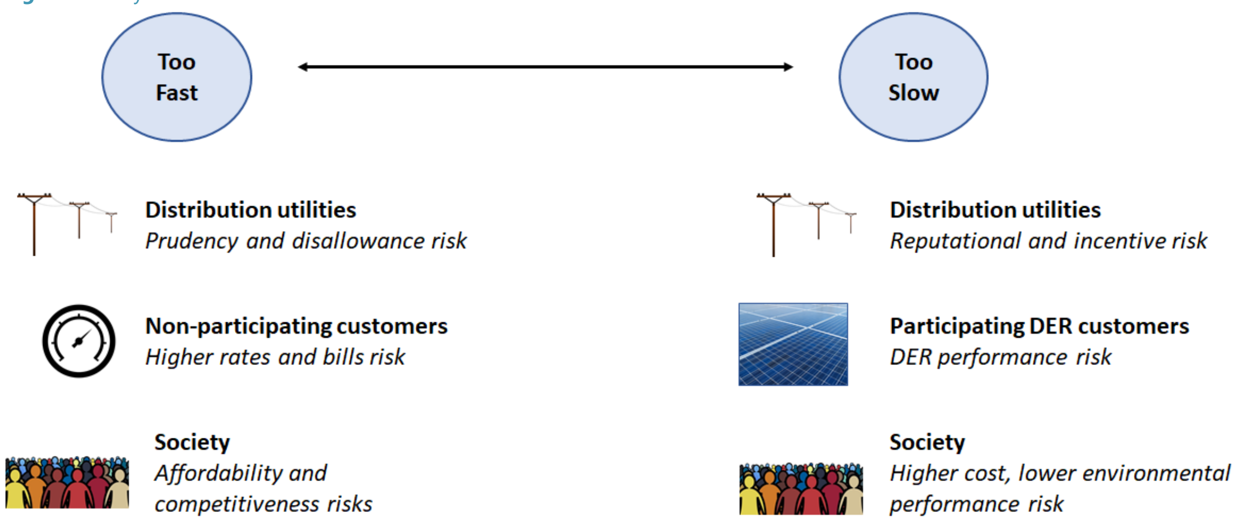
Managing risks and aligning incentives are central regulatory challenges for grid modernization. As distribution planners assess grid modernization investment needs, they face uncertainty in DER policies, DER adoption and load forecasts, DER technology performance, the availability and performance of grid technologies, and the baseline operating performance of different areas within the existing distribution system. Prioritization, spending limits, and ex-post assessment are tools for managing the risks associated with these different sources of uncertainty.

There are multiple drivers of grid modernization investment risk. Investments that are "too fast"—too far in front of need—may lead to excessive costs for customers or may be deemed imprudent by regulators. Investments that are "too slow"—lag too far behind need, or do not respond quickly enough to changing technologies—may lead to reliability and safety issues and expensive one-off fixes. Investments in the communications network, metering infrastructure, and grid or data management software may become obsolete before the end of its expected lifetime. In addition, technologies may be more expensive or may not perform as expected, leading to higher procurement costs, early replacement, or reliability and safety issues. Various jurisdictions and utilities may reasonably attach different weights to these risks.

Furthermore, disparate stakeholders face different risks. If the pace of grid modernization investment is too fast, utilities may face prudence and disallowance risks. Alternatively, if the pace is too slow, they may face reputational risk with regulators and customers and may not achieve incentive targets. Too fast a pace of investment could lead to higher costs for customers that do not own distributed generation, storage, EVs, or other distributed resources ("non-participating customers"), whereas too slow a pace could constrain participating customers' ability to realize the expected performance and value of their resources. For society, too fast a pace could lead to higher costs and affordability and competitiveness issues, whereas too slow a pace could lead to higher costs and emissions and non-achievement of state policy goals.

Figure 77 provides a high-level illustration of these different risks. A focus of regulators within grid modernization initiatives should be in reconciling these different stakeholder risks.

Figure 77. Key Risks to Different Stakeholders from the Pace of Grid Modernization Investments



Investment prioritization, spending limits, and routine ex-post assessment can help utilities and regulators navigate uncertainty and manage the risk tradeoffs among different stakeholders. Prioritization refers to the process of establishing investment priorities and sequencing investments over time, consistent with the grid modernization objectives, scenario-based needs assessment, functional gap assessments, and technology maturity assessments developed in a long-term strategic plan. The goal of prioritization is to identify least-regrets investments that balance risk, cost, and both short-term and long-term functionality and value.

Risk-based prioritization begins with identifying and ranking, or weighting, potential risks. Risk priorities can be incorporated into long-term strategic plans through scenario analysis. For instance, a long-term strategic plan might consider the availability and cost of different grid technologies over time, DER costs and forecasted rates of adoption, and electrification and other load growth factors.

Risks can also be incorporated into scoring systems that are used to prioritize investments. For instance, utilities and regulators may choose to prioritize investments on the basis of a range of characteristics, such as having joint benefits or enabling other investments, having high near-term value, enabling high-priority objectives, technological maturity and obsolescence risk, promoting learning or market development, or needed under conservative DER forecasts. Scoring systems provide a helpful tool for setting priorities and making tradeoffs under uncertainty.

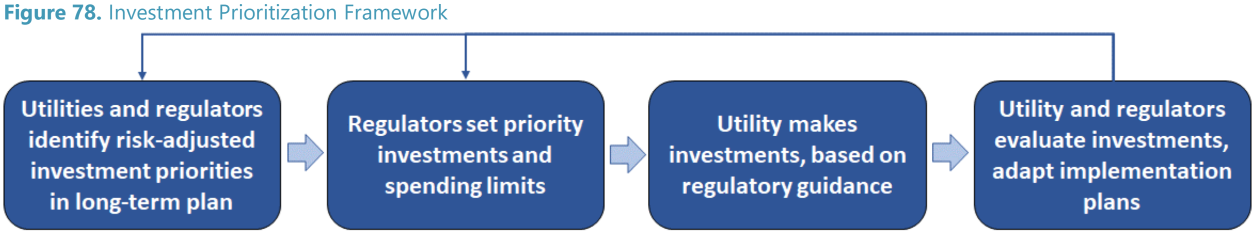
The Walk-Jog-Run approach introduced in Volume III also provides a tool for managing risk and uncertainty. Grid capabilities and functionality can be ramped up over time, incorporating a dynamic learning process, rather than requiring a large portfolio of grid modernization investments to be approved at once. Combined with ex-post assessment, a Walk-Jog-Run approach helps to reduce uncertainty over time as costs stabilize, technologies mature, and DER forecasts become more certain.

Within the Walk phase, pilots can be a helpful tool for evaluating the functionality and timing of investments. As the Minnesota Public Utilities Commission notes, "Allowing the utilities the opportunity to trial technologies and prove the benefits may be more useful than relying solely on utilities to show that certain investments are cost-effective from day one."[103] For instance, Austin Energy piloted a standalone DMS in 2008 but, realizing its limited functionality, decided to wait until 2011 and solicit proposals for an ADMS, which was operational in 2014.[104]

Investment spending associated with a grid modernization implementation plan may exceed levels that regulators deem reasonable, due to concerns over implementation, cost, and technology risks. To address these concerns, regulators can set multi-year spending limits that spread investments out over time and limit the risk in a given period. Spending limits reinforce the need for investment prioritization to determine which investments should move forward if there are spending constraints.

Figure 78 shows an illustrative framework for risk-based investment prioritization, where utilities and regulators identify priorities in a long-term plan based on an assessment that includes consideration of risks. Utilities and regulators use this framework to update their long-term and near-term plans, priorities, and spending limits.

Figure 78. Investment Prioritization Framework



5.6 Conceptual Application of Framework

This section presents an illustrative case that applies the economic evaluation and risk-based prioritization frameworks described above. The case is intended to illustrate how the framework could be applied rather than how it should be applied.

5.6.1 Case Background

A utility regulatory commission ("Commission") engages stakeholders to develop a high-level visioning document on grid modernization.[105] The state has multiple vertically integrated, investor-owned utilities. Utilities under the Commission's jurisdiction have not yet made significant investments in AMI or distribution monitoring, sensing, and control equipment and software, and have limited field communications networks. The grid modernization vision report lays out principles and broad objectives for a grid that is more information-rich, flexible, automated, secure, and resilient.

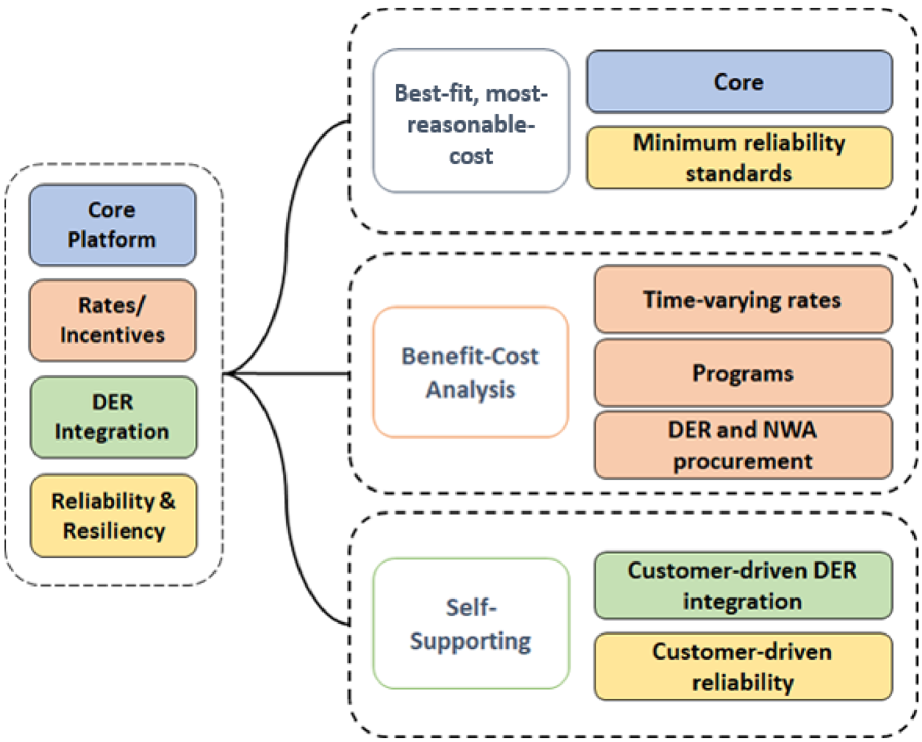
The state does not have specific resource targets for DER, but legislators have asked the Commission and utilities to prepare for a future with higher distributed PV, battery storage, and electrified transportation and buildings.

5.6.2 Organization and Prioritization

Based on the vision document, the Commission identifies a core set of objectives for grid modernization and organizes a grid modernization proceeding around three tracks: resiliency and reliability, rates/incentives, and DER integration.

The Commission orders the utilities to develop grid modernization strategic plans with 10-year planning horizons, to be updated every three years, that identify potential investment needs and strategies related to each of the three areas. The Commission requires the utilities to develop high-level benefit and cost estimates of investments but does not require a full benefit-cost analysis. This high-level benefit-cost analysis helps the Commission and utilities set expectations on the magnitude of expected benefits and costs. In the modernization strategic plan, the Commission directs utilities to categorize proposed investments by grid modernization objectives and four investment drivers (joint benefits, compliance, net benefits, and customer choice), consistent with Commission guidance and subject to Commission approval (**Figure 79**).

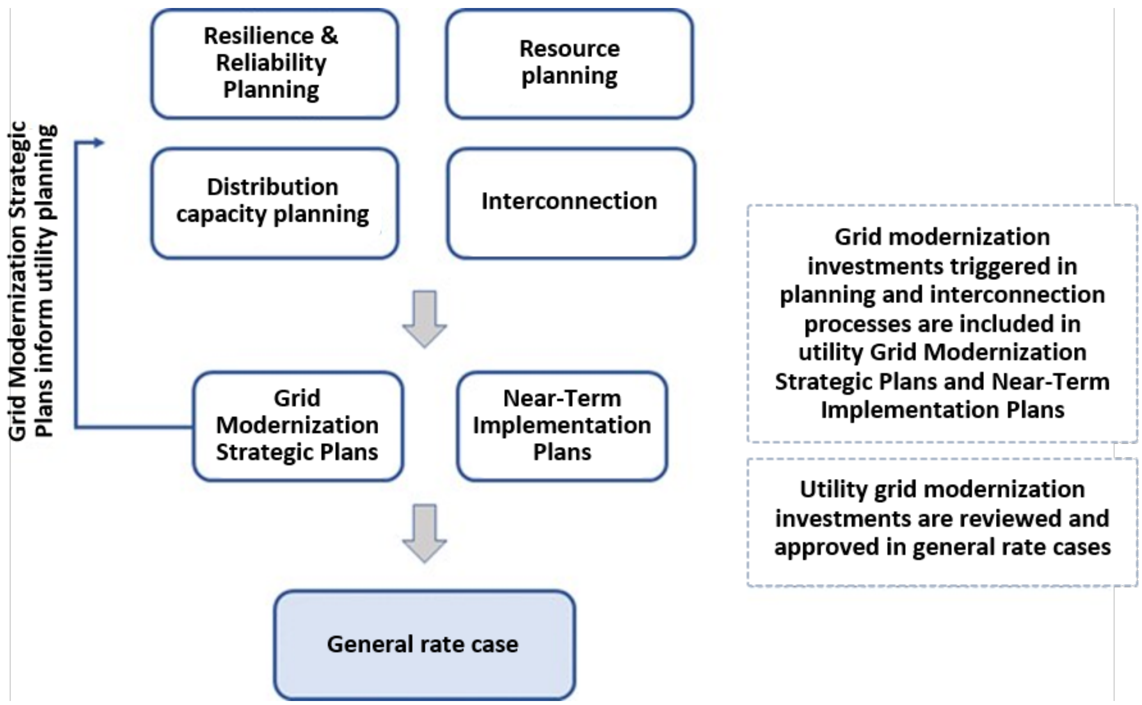
Figure 79. Utilities' Mapping of Objectives, Activities, and Evaluation Approaches



As part of the strategy, the Commission directs the joint utilities to develop a framework for identifying the risks associated with different grid modernization investments and asks each utility to develop a risk-based prioritization strategy for investments over the 10-year period. The joint utilities develop a scoring system to prioritize investments based on four metrics: joint and interdependent benefits, near-term value, technological maturity, and near-term need. As part of the three-year updates, the Commission directs utilities to update this strategy based on changes in technology and cost and ex-post assessment of investments.

Based on the strategic plan, the Commission also orders the utilities to develop grid modernization implementation plans with 5-year planning horizons, to be updated every three years, drawing on utility distribution and resource plans shaped by utility load and resource forecasts. The Commission establishes its general rate case proceeding as the integration point for different planning processes, where grid modernization related investments will ultimately be approved and incorporated into rates (**Figure 80**). The near-term implementation plans may correspond to one rate case cycle.

Figure 80. Illustration of Linkages Among Utility Plans and the General Rate Case



The Commission sets spending limits based on maximum rate increases ($/kWh) for each utility over a five-year implementation period due to grid modernization investments. Based on sales (kWh) forecasts, the Commission and utilities determine absolute spending limits over the period on core and compliance-related investments.

5.6.3 Core Investments

As part of the grid modernization plans, the Commission orders utilities to identify core investments that will be needed to meet nearer- and longer-term objectives for rate designs, DER integration, and reliability and resiliency, as well as to provide cost estimates, investment sequencing options, and timeline options for deployment. The utilities' assessment of core investment needs considers the functionality needed for DER integration over the next 10 years at different DER penetration levels.

The utilities identify and prioritize different core investments based on differences in forecasted DER growth. For instance, a predominantly urban utility that is anticipating higher DER adoption and multiple non-wires projects proposes communications network investments, ADMS, GIS, OMS, VVO, and FLISR as core investments. A predominantly rural utility that is anticipating lower DER adoption and limited distribution capacity constraints proposes communications network investments, ADMS, GIS, OMS, and FLISR as core investments. Each utility's implementation plans thus contains a different spending plan, with planned expenditures remaining within budget limits. The Commission reviews and approves the implementations, and the utilities use competitive solicitations to procure equipment and software outlined in the implementations.

The Commission directs utilities to develop performance metrics for core investments but does not require the utilities to conduct ex-ante benefit-cost analysis of these investments. Through discussions with the Commission and stakeholders, the utilities refine these performance indicators and develop the capability to calculate and regularly update them. Utilities also track installation performance for different core investments.

The Commission directs utilities to file a more comprehensive ex-post assessment of core investments as part of a review that accompanies three-year updates to grid modernization strategies, and to recommend and incorporate changes in the strategies and the next round of implementation plans based on that review.

5.6.4 Resilience & Reliability Track

In its resilience and reliability docket guidance, the Commission notes that new technologies are enabling higher levels of distribution reliability. The Commission directs the joint utilities to propose and comply with a minimum distribution reliability standard for their service territories.

To propose and comply with the standard, utilities begin an effort to improve the organization and evaluation of outage data and predictive capabilities. The utilities analyze historical data to identify main causes of outages and potential investment strategies for meeting the minimum standard. They develop predictive models using representative feeders to assess the impact of these different strategies on reliability metrics. They also evaluate different investments based on marginal effectiveness in improving reliability and cost, developing an investment portfolio for representative feeders that is consistent with lowest reasonable cost principles. The utilities then extrapolate the results from representative feeders to the rest of their distribution system.

Using this process, the joint utilities develop a reliability plan to inform a minimum reliability standard, including preliminary investment needs, estimated outage reduction benefits, and estimated costs. The Commission directs utilities to include a forecasted baseline—before any changes in rates or incentives—pertaining to the adoption of EVs, heat pumps, distributed generation, and customer-side batteries in their net-load forecasts for their proposed reliability standard. The joint utilities propose, and the Commission accepts and approves, a single minimum reliability standard for the state based on SAIDI, SAIFI, CAIDI, and CAIFI metrics.

Each individual utility develops a more detailed plan to meet and maintain the reliability standard, based on targeted improvements to worst performing feeders and OMS investments, which the Commission reviews and accepts. The Commission directs utilities to include proposed investments related to the reliability standard (and not already included in core investments) in their strategic and implementation plans, and to prioritize these investments under the spending limit. Utilities conduct competitive solicitation to procure equipment and software.

Utilities track and report detailed customer outage metrics. AMI implementation (see below) provides an important new source of outage information. The Commission directs utilities to integrate more granular reliability performance reporting into their regular reliability reporting, and to include the results of ex-post evaluation in its three-year strategy updates. Utilities use outage data and the results of ex-post evaluation to update predictive models.

5.6.5 Rates/Incentives Track

In the rates/incentives track, the Commission orders utilities to assess the benefits of time-varying rates (TVR) and other alternative rate designs for DER, including the benefits under different scenarios for transportation and building electrification. Utilities develop benefit-cost analyses to assess the cost-effectiveness of implementing the new rates including requirements for AMI, if not already deployed.

In the benefit-cost analysis, utilities develop scenario-based, base-case load shapes that include levels of projected "unmanaged" loads from transportation and building electrification under current flat rates. Utilities also develop scenario-based, change-case load shapes, based on expected response to TVR, including for EV charging and heating. For different scenarios, utilities evaluate the discounted energy, ancillary services, transmission and distribution deferral, and emissions benefits of AMI based on differences between the two cases.

Utility costs for AMI include both incremental metering, data management software, back office support, and marketing and education. Ex-ante evaluation provides a high-level estimate of the benefits of AMI for DER integration and reliability (outage management), which the utilities include as additional information in their filings.

Based on the results of the benefit-cost analysis, utilities propose different options for the timing of AMI deployment that are consistent with spending limits, reasonably accounting for expected operating cost savings (which would offset rate increases) and priority investments that have already moved to the implementation phase. Based on the results, the Commission approves full, but phased, implementation of AMI, beginning with opt-in customers and high "electrification potential" areas.

The Commission directs utilities to conduct an evaluation of performance and ex-post cost-effectiveness as AMI deployment progresses and at the end of deployment.

5.6.6 DER Integration Track

The Commission develops a white paper on DER integration challenges that identifies the potential investments needed to integrate distributed PV, storage, EVs, and demand response. The state's energy agency develops scenario-based forecasts of distributed PV, storage, EVs, and demand response adoption, incorporating expected rate changes in its adoption forecasts. The utilities work with the energy agency to develop hourly, area-specific, net-load forecasts that are consistent with these adoption forecasts. The energy agency and the utilities regularly update their forecasts.

Based on these forecasts, the utilities identify incremental investments and costs needed to integrate DER on different timescales and under different scenarios. In addition, the Commission directs utilities to regularly update integration costs. The utilities use these DER integration costs estimates in their resource procurement, non-wires procurement, and to inform their interconnection costs. The Commission then directs utilities to include any grid investments that are procured and paid for in resource or non-wires procurement in their grid modernization strategic plans and implementation plans. Any incremental investments are approved as part of the general rate case.

For grid investments that are triggered by distributed generation or storage interconnection requests, the Commission directs utilities to categorize investments into those that should be shared and those that should be paid for by individual customers, based on Commission guidance. The Commission directs utilities to track and report investments that are paid for by customers in their strategic and implementation plans.

What Did the Commission Do?

- Identified a core set of objectives for grid modernization and organized a grid modernization proceeding around those objectives.
- Ordered the utilities to develop long-term grid modernization plans and short-term implementation plans, and reviewed and approved plans.
- Ordered the utilities to categorize investments around objectives and drivers, and reviewed and approved categorization.
- Ordered the utilities to prioritize investments, accounting for a range of potential risks.
- Set spending limits for grid modernization investments.
- Ordered utilities to confirm core investments and develop and report performance metrics for evaluating their performance.
- Ordered utilities to propose and comply with a minimum distribution reliability standard, with regular outage metric reporting to evaluate compliance.
- Ordered utilities to assess the benefits and costs of TVR including related AMI costs and, post AMI installation, to evaluate and report actual benefits and costs on a periodic basis.
- Developed a white paper on DER integration challenges that identified potential investment needs.
- Ordered utilities to include grid modernization investments in their procurement and categorize DER interconnection costs, based on Commission guidance.

5.7 Key Takeaways

Grid modernization poses several challenges for traditional approaches to evaluating the economics of grid investments; grid modernization investments often have joint benefits, their benefits are often interdependent with other investments, and they may require multiple years to deploy and deliver desired benefits. A targeted evaluation of investments can help to address these challenges.

Objectives and planning are the cornerstone of economic evaluation frameworks for grid modernization investments. Objectives link investments to their expected benefits, and prioritization of objectives helps to establish investment priorities. Planning processes are integral to inform grid modernization strategy, evaluation, prioritization, and implementation.

Targeted evaluation of investments can be organized around four main drivers: joint and interdependent benefits (core investments), compliance with standards and policy mandates, net customer benefits, and customer choice. Each of these drivers maps to a different evaluation method: core and compliance investments are best assessed using a best-fit most-reasonable cost method; net-benefits investments are subject to benefit-cost analysis; and customer-driven investments are self-supporting, as they are assumed to be cost-effective. For core and compliance investments subject to a best-fit most-reasonable cost method, well-defined objectives and performance metrics are important for ensuring that investments are effective and efficient.

For benefit-cost analysis, increases in data granularity and computing power are enabling more integrated area- and time-specific assessments of grid modernization benefits and costs; new best practices are emerging.

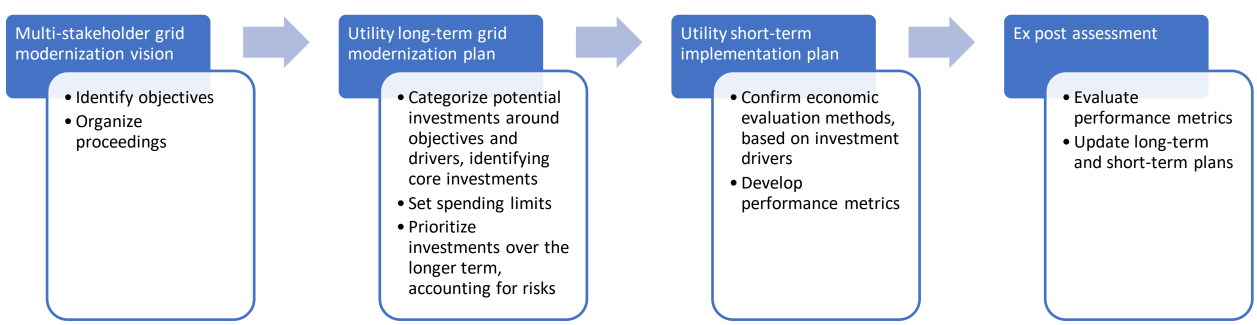
In addition, risk management is a critical consideration for how jurisdictions prioritize and evaluate investments. Utilities and regulators have multiple tools for incorporating risk into investment prioritization and evaluation decisions, such as scoring systems, pilots, spending limits, and regular ex-post assessment that promotes learning and adaptation.

In developing economic evaluation frameworks, regulators and utilities should concern themselves with the following questions:

1. What objectives do different investments support and what are their expected benefits?
2. What are the drivers of different investments and how should they be evaluated?
3. What are reasonable levels of spending and rate impacts for grid modernization investments?
4. What implementation and performance metrics should be used to evaluate investments?
5. How should risk management be incorporated into investment prioritization and decision-making?

Figure 81 shows an illustrative, high-level economic evaluation process for grid modernization investments, bringing together themes from the chapter.

Figure 81. Illustrative Economic Evaluation Process for Grid Modernization Investments



Glossary

A glossary is provided below for industry and technology terms as referenced in the DOE DSPx effort.[106]

Industry Definitions

Balancing Authority (BA) is the responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within an electrically defined Balancing Authority Area (BAA), and supports interconnection frequency in real time. A utility TSO or an ISO/RTO may be a balancing authority for an area.

Distributed Energy Resources (DERs) include distributed generation resources, distributed energy storage, demand response, energy efficiency, and electric vehicles that are connected to the electric distribution power grid.

Distribution System is the portion of the electric system that is composed of medium voltage (e.g., 69 kV to 4 kV) sub-transmission lines, substations, feeders, and related equipment that transport the electricity commodity to and from customer homes and businesses and that link customers to the high-voltage transmission system. The distribution system includes all the components of the cyber-physical distribution grid as represented by the information, telecommunication and operational technologies needed to support reliable operation (collectively the “cyber” component) integrated with the physical infrastructure comprised of transformers, wires, switches and other apparatuses (the “physical” component).

Distribution Grids today are largely radial, with sectionalizing and tie switches to enable shifting portions of one circuit to another for maintenance and outage restoration. Some cities have “network” type distribution systems with multiple feeders linked together to provide higher reliability and resilience.

Distribution Utility or Distribution Owner (DO) is a state-regulated private entity, municipal entity, or cooperative that owns an electric distribution grid in a defined franchise service area, typically responsible under state or federal law for the safe and reliable operation of its system. In the case of a vertically integrated utility, the distribution function would be a component of the utility. This definition excludes the other functions that an electric utility may perform. This is done in order to concentrate on the distribution wires service without confounding it with other functions such as retail electricity commodity sales, ownership of generation, or other products or services, which a vertically integrated utility may also provide.

Integrated Grid is an electric grid with interconnected DERs that are actively integrated into distribution and bulk power system planning and operations to realize net customer and societal benefits.

Independent System Operator (ISO) or Regional Transmission Organization (RTO) is an independent, federally regulated entity that is a Transmission System Operator (TSO), a wholesale market operator, a Balancing Authority (BA) and a Planning Authority.

Internet of Things (IoT) is the network of physical objects (or "things") embedded with electronics, software, sensors, and connectivity that enables the object to achieve greater value and service by exchanging data with operators, aggregators and/or other connected devices. Each object has a unique identifier in its embedded computing system but can interoperate within the existing Internet infrastructure.[107]

Local Distribution Area (LDA) consists of all the distribution facilities and connected DERs and customers below a single transmission-distribution (T-D) interface on the transmission grid. Each LDA is not normally electrically connected to the facilities below another T-D interface except through the transmission grid. However, to improve reliability, open ties between substations at the distribution level exist.

Markets, as referred to generically in this report, include any of three types of energy markets: wholesale power supply (including demand response), distribution services, and retail customer energy services. Markets for sourcing non-wires alternatives for distribution may employ one of three general structures: prices (e.g., spot market prices based on bid-based auctions, or tariffs with time-differentiated prices including dynamic prices); programs (e.g., for energy efficiency and demand response) or procurements (e.g., request for proposals/offers, bilateral contracts such as power purchase agreements).

Microgrid is a group of interconnected loads and DERs within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid. A microgrid can connect and disconnect from the grid to enable it to operate in both grid-connected and island modes.

Net Load is the load measured at a point on the electric system resulting from gross energy consumption and production (i.e., energy generation and storage discharge). Net load is often measured at a T-D interface and at customer connections.

Regulator is the entity responsible for oversight of the essential functions of the electric utility, including funding authorizations for power procurements, investments, and operational expenses. This oversight extends to rate design, planning, scope of services and competitive market interaction. Throughout this report, we use the term regulator in the most general sense to include state public utility commissions, governing boards for publicly owned utilities and rural electric cooperatives, and the Federal Energy Regulatory Commission (FERC).

Reliability Metrics[108] in the IEEE 1366 standard are used to assess the operational performance of the distribution system in terms of reliability and resilience. Some of the more commonly used IEEE 1366 metrics are:

- SAIDI (System Average Interruption Duration Index) – the total duration of interruptions for the average customer during a given time period. SAIDI is normally calculated on either a monthly or yearly basis; however, it can also be calculated daily, or for any other time period.
- SAIFI (System Average Interruption Frequency Index) – the average number of outages a customer experienced during a year.
- CAIDI (Customer Average Interruption Duration Index) – if a customer experienced an outage during the year, the average length of time the customer was out of power, in hours.
- MAIFI (Momentary Average Interruption Frequency Index) – the average number of outages a customer experienced during the year that are restored within five minutes.

Scheduling Coordinator/Entity is a certified entity that schedules wholesale energy and transmission services on behalf of an eligible customer, load-serving entity, generator, aggregator, or another wholesale market participant. This role is necessary to provide coordination between energy suppliers, load-serving entities and the transmission and wholesale market systems. This entity may also be a wholesale market participant.

Structure is an architectural structure created by the configuration of functional partitions in relation to actors, institutions and/or components and their relationships. Related structures include industry, market, operations, electric system, control, coordination, and communications.

Transactive Energy is defined by techniques for managing the generation, consumption, or flow of electric power within an electric power system through the use of economic or market-based constructs while considering grid reliability constraints. Transactive energy refers to the use of a combination of economic and control techniques to manage grid reliability and efficiency.[109]

Transmission-Distribution interface (T-D interface) is the physical point at which the transmission system and distribution system interconnect, typically at a distribution substation. This point is often the demarcation between federal and state regulatory jurisdiction. It is also a reference point for electric system planning, scheduling of power and, in ISO and RTO markets, the reference point for determining Locational Marginal Prices (LMP) of wholesale energy.

Transmission System Operator (TSO) is an entity responsible for the safe and reliable operation of a transmission system. For example, a TSO may be an ISO or RTO or a functional division within a vertically integrated utility, or a federal entity such as the Bonneville Power Administration or Tennessee Valley Authority.

Var is the standard abbreviation for volt-ampere-reactive, written “var,”[110] which results when electric power is delivered to an inductive load such as a motor.[111]

Technology Definitions

Advanced Distribution Management Systems (ADMS) are software platforms that integrate numerous operational systems, provide automated outage restoration, and optimize distribution grid performance. ADMS components and functions can include distribution management system (DMS); demand response management system (DRMS); automated fault location, isolation, and service restoration (FLISR); conservation voltage reduction (CVR); and Volt-var optimization (VVO).[112]

Advanced Metering Infrastructure (AMI) typically refers to the full measurement and collection system that includes meters at the customer site, communication networks between the customer and a service provider, such as an electric, gas, or water utility, and data reception and management systems that make the information available to the service provider and the customer.[113]

Customer Relationship Management (CRM) systems allow a utility to track and adjust marketing campaigns, forecast participation rates, and move customers from potential participants to fully engaged customers.[114]

Customer Information System (CIS) is the repository of customer data required for billing and collection purposes. CIS is used to produce bills from rate or pricing information and usage determinants from meter data collection systems and/or manual processes.[115]

Conservation Voltage Reduction (CVR) is an operating strategy of the equipment and control system used for VVO that reduces energy and peak demand by managing voltage at the lower part of the required range.[116]

Distributed Energy Resource Management System (DERMS) is a software-based solution that increases an operator's real-time visibility into the status of distributed energy resources and allows distribution utilities to have the heightened level of control and flexibility necessary to more effectively manage the technical challenges posed by an increasingly distributed grid.[117]

Demand Response Management System (DRMS) is a software solution used to administer and operationalize DR aggregations and programs. Building on a legacy of telephone calls requesting load reduction, DRMS uses a one-way or two-way communication link to effect control over and gather information from enrolled systems, including some commercial and industrial loads, and residential devices such as pool pumps, air conditioners, and water heaters.[118] DRMS allows DR capacity to be scaled in a cost-effective manner by automating the manual events that are typically used to execute DR events, as well as most aspects of settlement.

Distribution Management System (DMS) is an operational system capable of collecting, organizing, displaying, and analyzing real-time or near real-time electric distribution system information. A DMS can also allow operators to plan and execute complex distribution system operations to increase system efficiency, optimize power flows, and prevent overloads. A DMS can interface with other operations applications, such as geographic information systems (GIS), outage management systems (OMS), and CIS to create an integrated view of distribution operations.[119]

Distribution SCADA (DSCADA) is the application of supervisory control and data acquisition software to the distribution grid. SCADA is defined below.

Electric Vehicles (EVs) (also known as plug-in electric vehicles) typically derive all or part of their power from electricity. They include all-electric vehicles (AEVs) and plug-in hybrid electric vehicles (PHEVs).

Energy Management System (EMS) is a system to monitor, control, and optimize the performance of the transmission system and in some cases primary distribution substations.[120] The EMS is the transmission system's analog to the DMS.

Fault Location, Isolation, and Service Restoration (FLISR) include the automatic sectionalizing, restoration, and reconfiguration of circuits. These applications accomplish distribution automation operations by coordinating operation of field devices, software, and dedicated communications networks to automatically determine the location of a fault, and rapidly reconfigure the flow of electricity so that some or all customers can avoid experiencing outages. FLISR may also be known as Fault Detection, Isolation and Restoration (FDIR).

Geographic Information System (GIS) is a software system that maintains a database of grid assets, including transmission and distribution equipment, and their geographic locations to enable presentation of the electric power system or portions of it on a map.[121] GIS may also serve as the system of record for electrical connectivity of the assets.

Global Positioning System (GPS) is a system of satellites and receivers that determines the position (latitude, longitude, and altitude) of a receiver on Earth.[122] GPS is also used as a source of precision time signals for device synchronization.

Internet Protocol (IP) Packet Communication uses IP digital protocol to handle data in variable length packets that are routed digitally to their destinations asynchronously rather than making a fixed circuit connection or relying on fixed time intervals.[123]

Microgrid Interface is the set of power electronics at the Point Of Interconnection (POI)[xli] between the "island-able" portions of a grid, and the larger distribution grid, that support the essential microgrid[124] functions of islanding and reconnection.[125] The microgrid interface may also have the capability to provide services to the macro grid including Volt-var control.[xlii] As services are dropped from the distribution grid side of the interconnection, the microgrid interconnect disconnects, and the microgrid continues to provide service to critical loads in the islanded area.

Outage Management System (OMS) is a computer-aided system used to better manage the response to power outages or other planned or unplanned power quality events.[126] It can serve as the system of record for the as-operated distribution connectivity model, as can the DMS.

Reclosers are electro-mechanical devices that can react to a short circuit by interrupting electrical flow and automatically reconnecting it a short time later. Reclosers function as circuit breakers on the feeder circuit and are located throughout the distribution system to prevent a temporary fault from causing an outage.[127]

Supervisory Control and Data Acquisition (SCADA) systems operate with coded signals over communications channels to provide control of remote equipment of assets.[128]

[xli] Transitions at the POI are managed by the microgrid controller; see IEEE p2030.7.

[xlii] The impact of microgrids on the distribution grid is within the scope of this document, while the explanation of the operation of an islanded microgrid is not. Hence, the functionality of a microgrid is not explained here.

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