# Decoding DERMS

## Options for the Future of DER Management

IN PARTNERSHIP WITH

aps Xcel Energy EnergyHub

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# Decoding DERMS: Options for the Future of DER Management

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# Executive Summary

Utilities are increasingly required to incorporate distributed energy resources (DERs) into their planning and operations processes to improve flexibility and better manage distribution infrastructure. In part, the need for better integration of DERs is caused by increasing complexity of the grid due to the convergence of four major trends: growing variable renewable energy generation, increasing electricity demand, grid decentralization from the customer adoption of DERs, and a need to increase the resilience of the electric grid in response to extreme weather events.

Distributed energy resource management systems (DERMS) have emerged as critical tools to help utilities and market operators manage this complexity, better integrate DERs, improve system reliability and flexibility, and reduce system costs. This paper describes DERMS as a collection of multiple software systems interacting with utility operational and information technology (OT and IT) systems and business processes to enable a new paradigm for grid operations, allowing customer-sited resources to provide multiple grid benefits more quickly, flexibly, and affordably than traditional infrastructure investments.

No single software system can deliver all of the benefits DERMS can unlock for utilities today. Each of the software systems involved in utility DERMS implementations is sometimes referred to as a DERMS, adding to confusion. It is important to distinguish the two primary types of DERMS from one another:

- **Edge DERMS.** A system that manages large numbers of behind-the-meter (BTM) DERs of multiple types (e.g., batteries, thermostats, EVs, etc.) from multiple DER manufacturers.
- **Grid DERMS.** A system that is tightly interconnected with a utility's distribution OT systems and focuses on managing larger front-of-meter DERs and aggregations of BTM DERs, often through integration with an Edge DERMS.

This paper outlines key utility responsibilities, obligations, and goals and describes how each interacts and benefits from DERMS capabilities, including the development of long-term resource planning, system planning, operations, and DER program design, implementation, management, and evaluation. Each of these activities is linked and influenced by a range of factors, including business models for DER management and compensation.

**Key Takeaways**

- DERMS will help utilities address the trends of growing renewable generation, increasing electricity demand, customer adoption of DERs, and a need for increasing grid resilience.
- Investing in DERMS allows utilities to build and operate VPPs for peak load management and through multiple DER device types.
- DERMS enables a new approach to utility operations providing enhanced visibility and decision-making, providing multiple benefits beyond peak load management.
- There are multiple participation models for effectively managing DERs, each offering different advantages for capturing value from grid services.
- Utilities should consider an outcome-based procurement strategy and an incremental implementation approach for DERMS.
- Regulatory evolution is needed to ensure efficient investments.

Each DER participation model examined in this paper—including utility-led, aggregator-driven, hybrid, and dynamic pricing models—presents advantages and disadvantages for maximizing the benefits of DERs across the entirety of the electricity system (generation, transmission, and distribution). At this time and in this paper, however, the focus is on providing value to distribution systems through DERs and DER aggregations in the form of virtual power plants (VPPs). This represents the next stage of effective DER management as leading utilities have begun moving toward locational dispatch.

Implementing new technologies, or replacing legacy systems, can be challenging and drawn-out; taking an incremental approach to implementing DERMS provides the best path to success. Beginning with a set of clearly defined problems rather than seeking a monolithic, comprehensive solution to a host of issues allows utilities to take this type of incremental, solution-driven approach. Utilities taking a pragmatic approach often start by launching programs with a great customer experience, growing their VPP capacity, and building Edge DERMS functionality, before tackling complicated, long-term distribution system management challenges.

Of course, utilities do not operate in isolation. To fully realize the benefits that DERMS can provide and to clearly demonstrate their actual capabilities, regulatory evolution is required. This paper suggests that regulators incentivize DERMS investments as favorably as traditional capital expenditure projects, develop constructive participation frameworks, and establish incentive mechanisms that allow DER-based resources—and their enabling technologies—to be treated as equals with conventional generation, transmission, and distribution investments.

# Introduction

The electric grid in the United States is undergoing significant transformation driven by several major trends: the continued integration of renewable energy sources, increasing electricity demand, the decentralization of the grid due to the widespread adoption of distributed energy resources (DERs), and a need to increase the resilience of the electric grid in response to extreme weather events.

These trends have implications for how the distribution system is planned and operated. Utilities have many options to address these implications, including by building or expanding traditional infrastructure. However, if utilities focus solely on traditional generation, transmission, and distribution infrastructure, the costs could be significant, resulting in increased customer rates, and timelines that, in some instances, may be longer and incongruent with customer expectations.

## Major Trends Driving U.S. Electric Grid Transformation

### Growing Variable Renewable Energy Generation

The shift toward renewable energy,[1] driven by improved economics and state and utility decarbonization goals,[2,3] introduces variability into the grid and uncertainty into grid planning and operations. Solar and wind power are intermittent and require more sophisticated management strategies to ensure grid stability.[4]

### Increasing Electricity Demand

Electricity demand is growing due to increasing data center load,[5] industrialization, and the electrification of buildings and transportation.[6] This increased demand places additional stress on the distribution grid,[7] necessitating advanced management and optimization techniques.

### DER Adoption

The adoption of DERs, including rooftop solar panels, batteries, electric vehicles (EVs), and smart home devices, is transforming the traditional grid. Customers are no longer just consumers of electricity; they also use the grid more intensively and in ways not contemplated in the past by producing, storing, and dispatching energy.

### Grid Resilience

Increasingly extreme and costly weather events can threaten the reliability and stability of the electric power system. Utilities are turning to grid-scale and customer-sited distributed generation and storage, in addition to traditional resilience solutions, such as grid hardening, undergrounding lines, and vegetation management to provide options for grid resilience.

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1 Energy Information Agency (2025). Short-Term Energy Outlook. February 2025.

2 BloombergNEF (2025). Global Cost of Renewables to Continue Falling in 2025 as China Extends Manufacturing Lead: BloombergNEF.

3 Smart Electric Power Alliance (2025). Utility Carbon Reduction Tracker.

4 National Renewable Energy Laboratory (n.d.) Renewable Energy Integration.

5 Canary Media (2024). Data centers are driving US power demand to hard-to-reach heights.

6 Lawrence Berkeley National Laboratory (2023). Managing the peak demand impacts of building and transportation electrification through energy efficiency and demand flexibility.

7 Kevala Inc. (May 2023). Electrification Impacts Study Part 1: Bottom-up Load Forecasting and System-Level Electrification Impacts Cost Estimates. Prepared for the California Public Utilities Commission Proceeding R. 21-06-017.

Nationwide, electricity demand is forecasted to increase by almost 16% by 2029.[8] Whereas traditional generation can take years to build and even longer to interconnect,[9] virtual power plants (VPPs) and other DERs can be launched and scaled quickly at 40-60% lower cost, and provide operators with options for managing the grid during resource adequacy events.[10,11] Distributed energy resource management systems (DERMS) and changes to grid planning and operations have the potential to allow utilities to meet the needs of the future at much lower cost and with greater speed and optionality by diversifying utility energy portfolios, deferring distribution investments, and providing incremental capacity and operational flexibility.

To harness the potential benefits of DERs and VPPs, utilities and market operators are turning to DERMS.[12] DERMS is a collection of software systems that interact with utility operational and information technology (OT and IT) systems to integrate, manage, and optimize DERs, supporting more reliable and efficient grid operations. By providing real-time monitoring, control, and coordination of both front-of-the-meter (FTM) and behind-the-meter (BTM) assets, DERMS facilitates a new paradigm for grid operations. **With DERMS, utilities can build and scale VPPs that provide reliable flexibility by leveraging DERs to shift and shape load.**

**The Aim of This White Paper**

- Clarify the terminology around DERMS, VPPs, and aggregators.
- Define useful participation models for DER management.
- Outline utility business processes for integrating and managing DERs.
- Describe an architecture for DERMS.
- Discuss strategies for paying for and implementing DERMS.

# Why DERMS Now?

As customer adoption of DERs grows, their impact on the bulk- and distribution-level grid systems becomes more pronounced.[13] Historically, state-level policies and incentives that have led to robust DER adoption have not required DERs to be utilized in a way that provides coordinated value to the grid. While DERs can benefit the grid to the extent that their operation may coincide with system needs, utilities cannot reliably plan and operate their systems under this more passive DER model. However, more actively managing and integrating DERs can improve grid reliability, power quality, and system resilience, provide economic value to both utilities and customers, and reduce emissions. On the other hand, uncoordinated DERs can increase peak system demand, create distribution overloads or voltage violations, and increase the risk of cascading blackouts.[14]

Utility efforts to harness customer-sited DERs for grid benefits started with traditional demand response programs. Technological and programmatic innovations have led utilities to consider broadening the scope of these programs. In recent years, VPPs have emerged as a programmatic mechanism combining one or more DER types that can be deployed to provide utility-scale and utility-grade grid services. The primary reason utilities should invest in DERMS is to build and operate VPPs.

In the context of demand flexibility (the ability to adjust when and how electricity is used in response to grid

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[8] Clean Grid Initiative (2024). Strategic Industries Surging: Driving US Power Demand.

[9] Lawrence Berkeley National Laboratory (2024). Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection.

[10] Brattle (2023). Virtual Power Plants (VPPs) Could Save US Utilities $15-$35 Billion in Capacity Investment Over 10 Years.

[11] Portland General Electric (2024, July 11). PGE customer actions resulted in the largest electricity demand-shift in company history during multi-day heat wave. Portland General Electric.

[12] Smart Electric Power Alliance (2025). 50 States of Virtual Power Plants and Supporting Distributed Energy Resources: 2024 State Policy Snapshot.

[13] Navidi, T., Gamal, G., & Rajagopal, R. (2023). Coordinating distributed energy resources for reliability can significantly reduce future distribution grid upgrades and peak load. *Joule*.

[14] Electric Power Research Institute (2020). Grid Impacts from Distributed Energy Resources.

conditions, pricing signals, or other factors) VPPs or aggregations of DERs serve two important purposes:

- For utilities, they can be dispatchable resources to help manage grid constraints.
- For customers, these resources can reduce bills and provide resilience benefits, among others.

The term "DERMS" is broadly used to describe software systems designed to manage DERs. However, there are competing definitions of what a DERMS is and what it should do. This paper defines DERMS as a collection of multiple software systems that interact with utility OT and IT systems to enable a new paradigm for grid operations.

## Benefits of DERMS

Effective DER management will require software systems to coordinate customer and grid objectives, choose optimal settings for DERs, communicate those settings to devices, report performance, and autonomously orchestrate these actions. This is the role of DERMS. The benefits provided by DERMS are clear and include—but are not limited to—the following:

- Reduce the need for new generation capacity and bulk grid transmission expansion by better managing peak loads.
- Reduce energy supply costs for both consumers and utilities by shifting net load from high-cost to low-cost periods.
- Reduce distribution asset overloading, extend the life of existing assets, and slow the need for upgrades.
- Improve distribution system power quality and reduce line losses through improved voltage management and optimization of both active and reactive power from DERs.
- Support the deployment of least-cost non-wires alternatives.
- Enable the flexible interconnection of DERs to the distribution grid, potentially deferring the need for expensive hosting capacity upgrades.
- Support bulk grid reliability by delivering ancillary services, such as operating reserves and frequency regulation.

DERMS can provide a wealth of benefits for utilities and their customers. They also help utilities prepare for all types of DERs, including nascent technologies such as vehicle-to-grid and home energy management systems.

## Types of DERMS

There is no single software system that can deliver all of these benefits today. Instead, utility DERMS implementations likely will involve multiple software systems, each of which is sometimes referred to as a DERMS and the technology for which is rapidly evolving. These may include the following examples and definitions:

- **Edge DERMS:** A system that manages large numbers of primarily behind-the-meter DERs of multiple types (e.g., batteries, thermostats, EVs, etc.) from multiple DER manufacturers. An Edge DERMS that only manages demand response assets is sometimes referred to as a Demand Response Management System (DRMS). These are also sometimes known as Aggregator DERMS. These systems are typically implemented and managed by the customer and program management teams at utilities.

  Examples: EnergyHub, Virtual Peaker, Uplight.
- **Grid DERMS:** A system that is tightly interconnected with a utility's distribution OT systems, such as an advanced distribution management system (ADMS) and/or supervisory control and data acquisition (SCADA)/energy management system (EMS), and focuses on managing larger FTM DERs and aggregations of BTM DERs, often through integration with an Edge DERMS. These are sometimes also known as Utility or Enterprise DERMS. These systems are typically implemented and managed by utility planning or operations teams at utilities.

  Examples: GE, AspenTech OSI, OATI.
- **Aggregator/Original Equipment Manufacturer (OEM) DERMS:** A system for first-party use by an aggregator or OEM for their economic benefit and not to manage the grid.

  Example: Tesla PowerHub.
- **Microgrid/Building Management Systems:** In some rare cases, a microgrid management system will be referred to as a small DERMS.

  Example: Pxise.

This white paper focuses on the first two DERMS definitions, with an emphasis on how Edge DERMS and Grid DERMS effectively operate and work together.

**Figure 1. Examples of DERs**

Source: SEPA (2025).

# Participation Models for Managing Aggregations of DERs

If DERs are an important part of future grid operations, then it is necessary to develop participation models that enable the various parties in the larger DER ecosystem to play their respective roles.

These participation models should ensure that grid-connected DERs effectively contribute to key industry objectives, such as reliability, managing costs, and emissions reduction. These models should enable multiple stakeholders in the distributed energy industry to contribute productively to these goals, including electric utilities, DERMS technology vendors, DER OEMs, DER aggregators, and customers.

## Utility-Led Model

The utility-led model involves utilities managing DERs to capture value across the value chain: generation, transmission, and distribution. This model requires investment in DERMS technology that enables utilities to optimize customer-sited DERs according to defined objectives while capturing multiple value streams.

Utility DER program models may take one of many forms—mainly dispatchable and non-dispatchable—and vary based on the customer-sited DER itself and the objective of the DER program. Dispatchable program models include direct-load control (utility-managed), third party-aggregator managed, tariffed/contracted, pay-for-performance, and committed capacity. Non-dispatchable programs include time-varying rates, behavioral, and solar PV.

For dispatchable programs, dispatch control can follow one of two general options or a combination of both: (1) direct load control, where the utility maintains granular control of DERs, for example under "Bring-Your-Own-Device" models or (2) aggregator-mediated control, where third parties receive utility/market signals and determine the optimal device-level responses. These approaches support compensation structures from simple participation incentives to performance-based models with or without contractual commitments, like Xcel (CO)'s recent aggregator VPP tariff proposal.[15]

Current market examples illustrate the rapidly evolving regulatory landscape, with utilities like Arizona Public Service (APS) utilizing DER assets in concert with wholesale markets. This highlights ongoing discussions about market participation and the balance between utility-controlled programs and access for competitive DER aggregators. Figure 2 shows the utility-led model.

In the utility-led model, DERMS addresses both bulk and distribution system challenges through comprehensive DER management. Utilities employ economic and/or operational evaluation mechanisms to determine and optimize DER dispatch or scheduling, with aggregators or Edge DERMS-managed OEMs participating through utility programs or tariffs rather than directly in the market. This model establishes participation agreements between utilities, OEMs, and customers, allowing the utility to capture multiple value streams while maintaining flexibility in program structure and evolution. Regulators play a crucial role in the utility-led model by encouraging utilities to quantify benefits, like deferral of distribution investments, while supporting incremental program

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[15] Colorado Public Utilities Commission (2025). Docket No. 25A-0061E. Colorado Department of Regulatory Agencies.

development. Instead of limiting utility earnings to peak load management, regulatory frameworks should create mechanisms to reward utilities for implementing cost-effective programs that deliver multiple services like peak management, daily load shifting, distribution management, and ancillary services.

## Advantages

- Streamlined customer experience through uniform program offerings.
- Consistent marketing across the utility service territory.
- Complete distribution management control for utilities.
- System-wide optimization of potentially conflicting objectives across generation, transmission, and distribution levels.

## Disadvantages

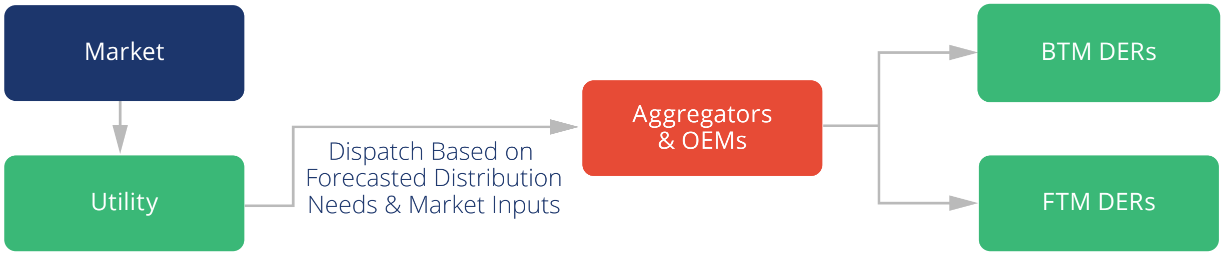
- May limit customer choice given single program offering from utility.
- Potentially limits competition and innovation from aggregators.

# Aggregator-Driven Model

In the aggregator-driven model, third-party providers enroll directly with ISO/RTO market operators to sell grid services, while utilities maintain oversight of and control over dispatch decisions to ensure that DER aggregator operations do not have detrimental impacts on the operation of the distribution system. This arrangement features minimal direct utility control of DERs, instead focusing on wholesale market participation for capacity and/or energy value streams (Figure 3).

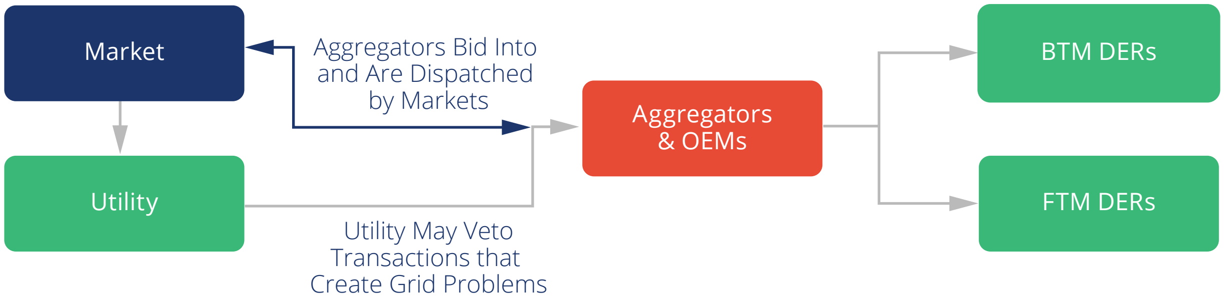
For successful implementation, the aggregator model must incorporate lessons from utility-driven approaches while addressing its inherent limitations (from the aggregator perspective). This includes developing mechanisms to preserve program branding and customer relationships,

**Figure 2. Utility-Led Model**[16]



Source: EnergyHub (2025). Recreated by SEPA.

**Figure 3. Aggregator-Driven DERMS Model**



Source: EnergyHub (2025). Recreated by SEPA.

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[16] In this and the following figures in this chapter, "market" simply refers to a generalized representation of any utility wholesale contracting for generation or other services; the "market" is not just an ISO/RTO operated market and this model is equally applicable in both vertically integrated and restructured states.

establishing frameworks that enable the capture of distribution system deferral values, and creating sufficient visibility for system operators while maintaining competitive benefits.

### Advantages

- Expanded customer choice through competitive offerings.
- Diversified performance risk.
- Greater agility in program development and iteration.

### Disadvantages

- Customer confusion from numerous competing offerings.
- Difficulty in implementing region-specific OEM-led marketing campaigns.
- Limited utility visibility and control over distribution system impacts.
- Challenges in capturing distribution system benefits.
- Limited regulatory oversight of aggregators.

## Hybrid Models

A hybrid approach to DER program management could combine elements of the utility-led and the aggregator direct participation models to maximize the benefits captured across the generation, transmission, and distribution value chain. This framework—conceptually aligned with FERC Order 2222's market participation objectives—potentially could enable DERs to respond simultaneously to wholesale market signals and utility distribution needs through coordinated mechanisms. Although programs like ConnectedSolutions[17] incorporate some hybrid elements, a fully integrated model remains largely theoretical, apart from an interest in balancing utility control with competitive market participation.

The implementation of hybrid models presents significant challenges, particularly concerning the potential double-counting of resource commitments and conflicting dispatch signals. Cautious coordination protocols and clear rules would be necessary to prevent resources from being simultaneously committed to incompatible services.

As FERC Order 2222 implementation advances across ISOs/RTOs, these hybrid approaches may gain relevance, requiring more thoughtful regulatory frameworks that preserve distribution system reliability while enabling broader market participation and value creation.

### Advantages

- Balanced utility control with competitive market participation.
- Potential for optimized value capture across multiple value streams.

### Disadvantages

- Potential for double-counting resource commitments and conflicting dispatch signals.
- Requires careful coordination and clear rules to prevent conflicts.

## Dynamic Pricing Only

In a pure price-based model, utilities provide market signals, such as dynamic electricity prices, designed to incentivize DERs to deliver grid services when and where they are needed. The pure price signal model for DER integration is grounded in economic theory that holds that market signals will guide customer adoption and operation without utility intervention. Economists favor this approach due to its theoretical simplicity and technology-neutral stance, potentially reducing the need for DERMS as customers and devices could respond autonomously to price signals. At the bulk system level, this market-driven model has gained traction in regions like Texas and parts of Europe with varying levels of success.

Practical limitations challenge this model's effectiveness. As renewable energy at the bulk system level grows, price signals must become increasingly dynamic and geographically granular to maintain grid reliability, a complexity that may overwhelm retail customers with DERs. The model also struggles to address extreme events (e.g., Winter Storm Uri) where price caps may be necessary to protect customers, thereby undermining the economic efficiency principles upon which the model rests. Most challenging, translating distribution-level constraints into meaningful price signals introduces significant problems, as no current system successfully integrates wholesale market conditions and distribution-level constraints into cohesive retail rates. Further, the utility rate setting process

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[17] ConnectedSolutions is a virtual power plant model developed by utilities in Massachusetts, Connecticut, and Rhode Island.

typically prohibits utilities from setting rates that could be perceived as inequitable and the process also takes significant time to work through the regulatory process.

The model's greatest weakness lies in its inability to enforce physical grid constraints through pricing alone and to provide any guarantee that DERs will deliver grid services when and where they are needed. In other words, while price signals may encourage customers or aggregators to behave in certain ways, there is no guarantee that the expected outcome will occur. This is an important distinction for leveraging DERs on the distribution system where planners and operators have a more limited and drastic set of actions available to them should DERs not perform as expected.

For example, on the bulk system, if a DER aggregation does not perform as expected, replacement power can typically be purchased in the spot market (albeit typically at a higher price). Conversely, if DERs do not reduce loading on the distribution system, there is no "market" an operator can turn to solve the physical constraint. In turn, this may require more operationally complex mitigations such as manually switching load to adjacent feeders or, in the worst case, opening up protective equipment to drop customer load—a process which can lead to unexpected outages for customers.

While some jurisdictions are exploring congestion pricing, price signals alone cannot algorithmically prevent actions that could damage utility infrastructure, such as batteries discharging into already overloaded transformers. This fundamental limitation suggests that, while price signals play an important role, it likely requires complementary control systems to ensure safe and reliable grid operations.

### Advantages

- Simplicity and technology-neutral stance.
- Reduced need for DERMS as customers respond autonomously to price signals.

### Disadvantages

- Challenges in addressing extreme events and maintaining grid balance.
- Limited ability to enforce physical grid constraints through pricing alone.

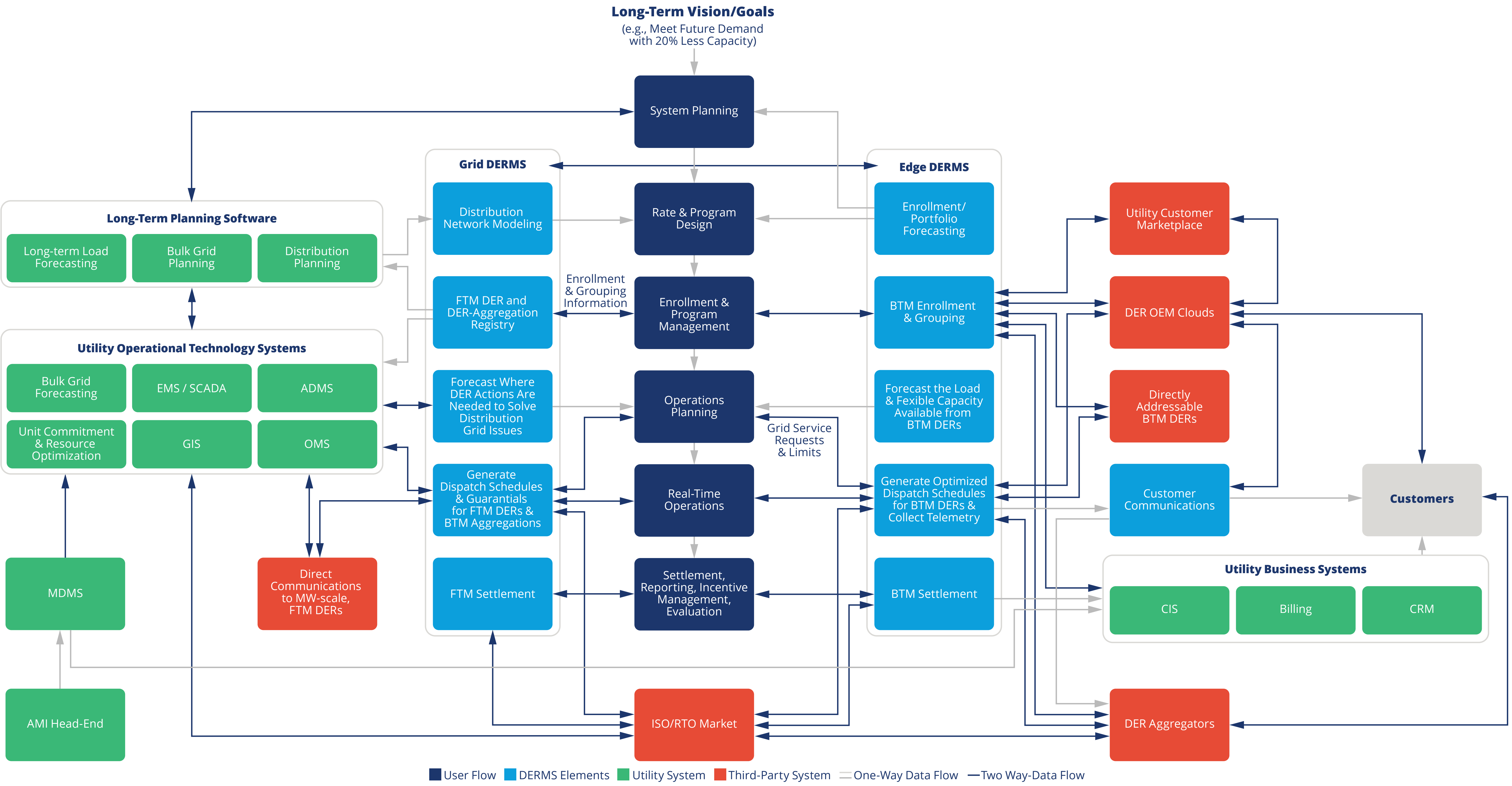
## DERMS Architecture and Utility Business Processes

Given the essential role of DERs in the future of power system operations, it is important to understand what a DERMS is and how it integrates with other utility IT and OT systems and corresponding business processes.

This section describes a DERMS architecture that includes both an Edge and a Grid DERMS and explains how those systems interact with utility processes and software systems. This architecture is somewhat abstract: there is no existing commercially available solution that perfectly matches this design. This design should be thought of as an ideal end state and not something that can be built all at once. The section "Paying for and Implementing DERMS" discusses implementation strategies that can be used to move toward this vision in phases.

Figure 4 provides a high-level overview of this proposed DERMS architecture, along with its interconnections to other key utility systems.

**Figure 4. DERMS Architecture Diagram**



Source: EnergyHub (2025). Recreated by SEPA.

## System Planning and Rate and Program Design

DERMS generates data that the utility can use to inform its planning and design processes. Looking forward, DERs can serve two critical functions in utility system planning: (1) reducing net load during key periods to delay infrastructure investments and (2) providing actively managed resources to address future system constraints. DERMS platforms gather valuable information from initial DER deployments that can be used to develop data-driven forecasts of DER program growth and performance.

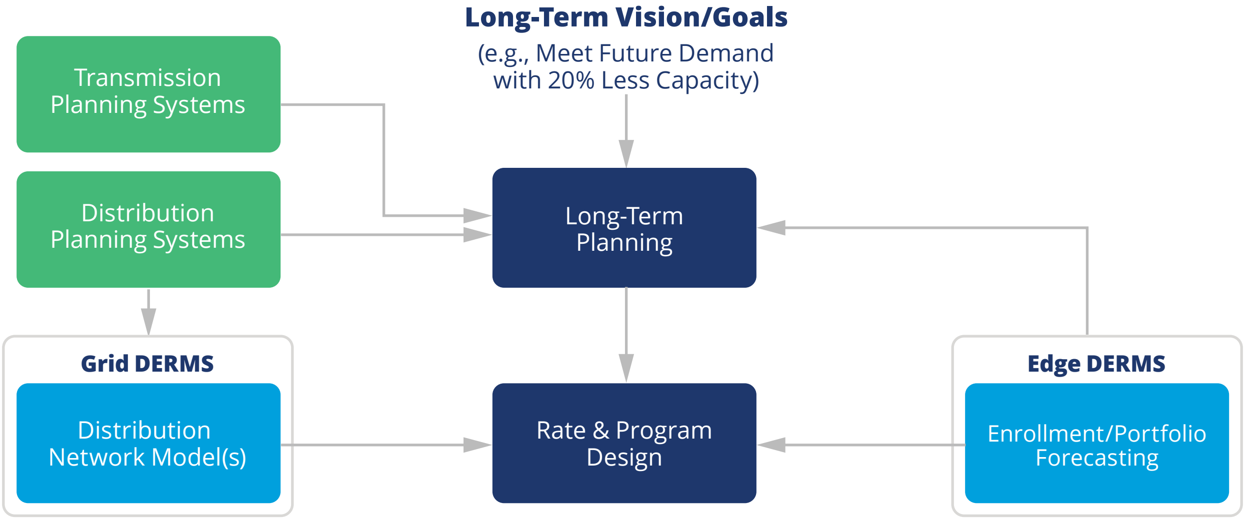
Utilities routinely perform a range of system planning activities affected by DERs, including:

- **Generation Planning**—The integration of renewable generation has shifted traditional planning from simple seasonal peaks to dynamic scenarios influenced by variable resource availability. This complexity, driven by differences between weather-dependent and fully dispatchable generation, necessitates enhanced dispatchability from DERs to ensure reliable grid operation.
- **Transmission Planning**—The current transmission system, designed for centralized generation, often requires upgrades when interconnecting variable renewable energy. Utilities and grid operators must develop robust capacity forecasts and incorporate effective load-carrying capability assumptions to leverage DERs for addressing transmission constraints and supporting system reliability.
- **Integrated Resource Planning**—Integrated resource plans (IRPs), which balance supply and demand, must include DERs as resources to address load growth and reserve margins. While vertically integrated utilities benefit from streamlined planning, ISOs/RTOs introduce complexity, requiring utilities to comply with broader market rules, which can complicate DER integration.
- **Distribution System Planning**—Distribution planning, challenged by increasing DER penetration, requires accurate load forecasting and dynamic modeling to understand DER impacts. Utilities can use DERMS and advanced analysis to identify opportunities for DER deployment to defer or alleviate the need for infrastructure upgrades.

### What Might System Planning with Grid and Edge DERMS Look Like?

With an Edge DERMS, a utility may use historical enrollment growth rates to project the growth in flexible capacity from a battery or thermostat program. Alternatively, the utility may work with an Edge DERMS provider to understand how different incentive designs will impact future DER enrollments or performance. Since this type of analysis does not require real-time interactions, the Edge DERMS does not require deep IT/OT integration at this phase. In some cases, it may be useful to use a business intelligence (BI) system, such as Tableau or Power BI, to facilitate visualization of the Edge DERMS data.

**Figure 5. System Planning, Rate and Program Design, and DERMS**



Source: EnergyHub (2025). Recreated by SEPA.

A Grid DERMS may be used to understand where in the distribution system there is a need for additional grid services from DERs or where DERs could be implemented for using flexible or active management approaches. For example, Grid DERMS may identify that a particular feeder will need 500 kW of DR capacity on hot summer days, but only 300 kW is available. This information could be used to inform the inclusion of a locationally targeted customer marketing element in the program design. The primary integration needed to facilitate this planning is with the utility's distribution system modeling software so that Grid DERMS can identify distribution system issues and concerns.

Once a program design is chosen, the Edge DERMS will need to keep track of program settings so that these can be used in subsequent processes like program management and operations planning.

## Enrollment and Program Management

Once the program is launched, both Grid DERMS and Edge DERMS need to keep accurate records of which DERs and DER aggregations are enrolled or in some other way available for responding to control instructions.

For most behind-the-meter DER programs, such as bring-your-own thermostats or battery programs, Edge DERMS should play a primary role in tracking which DERs are enrolled. This often requires integrating with multiple DER OEM cloud software systems so that OEMs can notify the Edge DERMS when a customer would like to enroll in a program. Verifying that a particular device/location is eligible for a particular program may require integration with the utility Customer Information System (CIS).

The Edge DERMS will also need to organize devices into logical groups based on common characteristics, such as DER class (batteries, thermostats, C&I sites, etc.), rate class, and grid location. Putting a device into an accurate grid location group (substation, feeder, feeder section, transformer, etc.) is necessary so that a group of devices behind a particular grid constraint can deliver the appropriate grid service (voltage management, load reduction, etc.) for that particular location, when needed. Grouping based on grid topology likely will require integration with the Grid DERMS or some other system, like ADMS, that can use locational information (address, meter ID, etc.) to generate topological groups.

To keep the DER groups up-to-date, the Grid DERMS will need to work closely with systems that keep track of grid topology changes, such as ADMS. This is a critical capability as the distribution system experiences more frequent topology changes (e.g., due to planned and unplanned outages, field switching, etc.) compared to the transmission system. This will likely result in periodic re-grouping of devices based on changes to feeder configurations due to seasonal changes or planned maintenance.

Once topological groups have been created at logical levels of granularity, such as the feeder or feeder section, each of these groups can be considered to be a single aggregated distributed resource with describable characteristics (power and energy capacity, dispatch limitations, etc.).

**Figure 6. Utility DER Program Enrollment Process and DERMS**

Source: EnergyHub (2025). Recreated by SEPA.

## Operations Planning

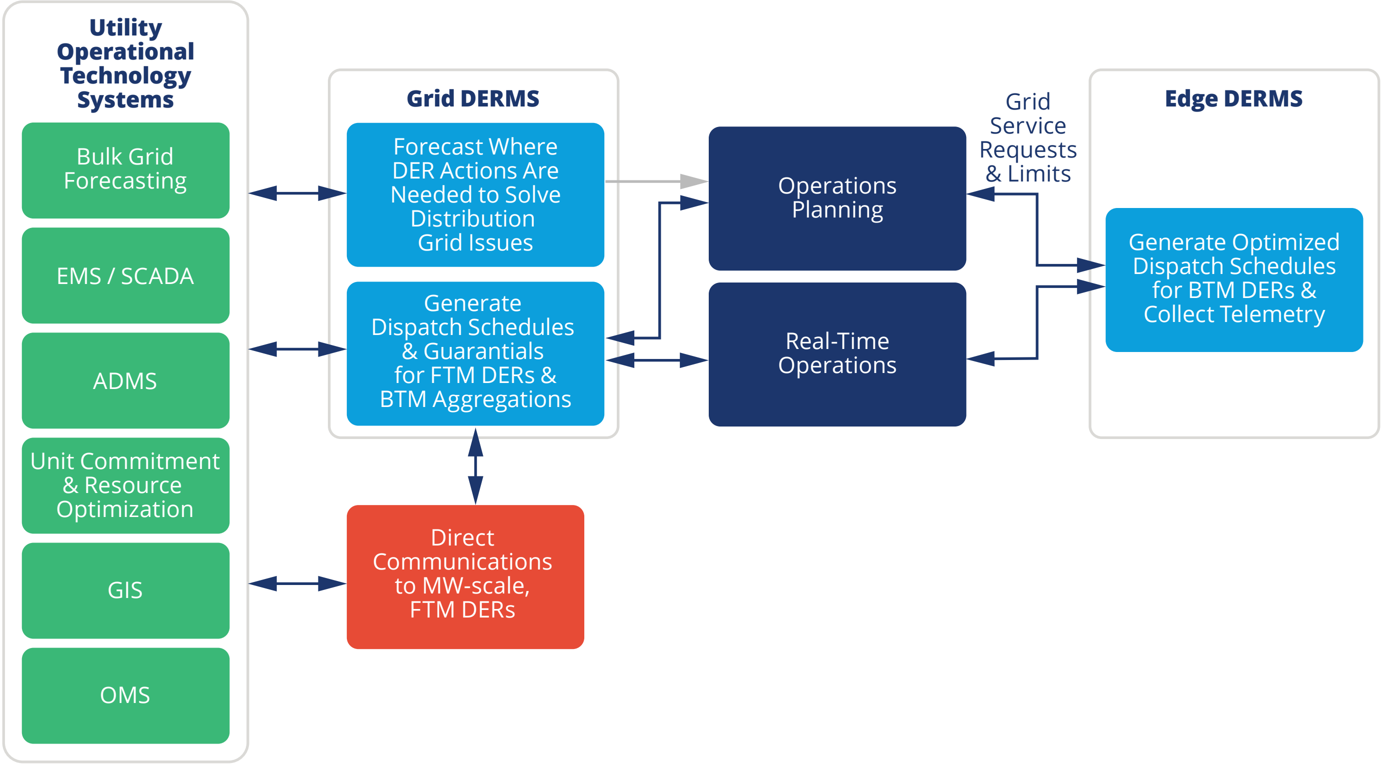
Most medium-to-large utilities have multiple operations planning teams that develop plans for generation, transmission, and distribution systems over 1-14 day time horizons. As a utility's VPP capacity grows, there will be an increasingly important role for DERMS in providing useful forecasts into operations planning processes and providing scheduling tools that can be used to integrate DERs into operations planning processes.

Grid DERMS should first focus on identifying (either through forecasting or real-time monitoring) where there are constraints in the distribution system that could be addressed by DERs. For example, this process may identify a distribution substation transformer that will approach its thermal limits during hot weather two days from now. To accurately understand the extent to which DERs can mitigate identified issues, Grid DERMS will then need to estimate the flexible capacity that it will have available from both utility-scale and BTM DERs. Grid DERMS will likely collect this information directly from SCADA-connected DERs. For BTM DERs, Edge DERMS should be able to respond to requests from Grid DERMS for a forecast of both baseline load and forecasted flexible capacity (flex up and flex down) for time periods of interest.

Edge DERMS, potentially through Grid DERMS, will also need to communicate aggregated forecast information to the utility's unit commitment or resource optimization system, so that the utility can schedule VPP dispatch schedules in concert with other grid resources and market transactions (batteries, power plants, market purchases, etc.). If a utility is going to choose not to commit a thermal unit on a future day, they will likely need to know not only how much dispatchable capacity is available, but also an accurate estimate of the uncertainty in the forecast information.

In some implementations, DERMS can manage DERs autonomously based on utility-specified goals. For example, DERMS may monitor a data feed from the ISO and trigger a VPP response if regional loads exceed a certain level. In other cases, for example, an Edge DERMS may optimize EV charging (or discharging in the V2G case) schedules to minimize wholesale or retail energy costs, while satisfying customers' charging requirements and

**Figure 7. Utility Operations Systems and Connections**



Source: EnergyHub (2025). Recreated by SEPA.

keeping loads within specified limits. Edge DERMS will typically be responsible for creating these schedules, so Grid DERMS will need to communicate the limit groups and limit values (sometimes known as dynamic operating envelopes) to the Edge DERMS. During operations planning time frames, DERMS (both Grid and Edge) should provide utilities with the ability to adjust the settings for autonomous operating modes of this sort.

## Real-Time Operations

During real-time operations, DERMS has four primary responsibilities.

- First, they need to provide information to grid operators about how much capacity is available if they decide that they need DERs to deliver a grid service, such as system-wide peak load reduction or locational load shifting. For example, DERMS may tell operators that there is 4 MW of flexible capacity during the afternoon hours from Substation X. If operators determine that they need to use some or all of the available capacity, then DERMS needs to determine how to execute. They may, for example, request a load reduction at Substation X by 2 MW for 3 hours starting at 4:00 PM.
- Second, DERMS needs to execute automated grid services that it has already been asked to deliver through automated systems. For example, DERMS may automatically dispatch batteries and EVs to shift load to reduce wholesale electricity costs while keeping net load within limits.
- Third, DERMS needs to deliver telemetry data to grid operators so that they have situational awareness of ongoing DER activities that have system implications.
- Finally, DERMS will need to communicate with DER aggregators about actions that they should or should not take. For example, DERMS may send a "stop" or "limit" command to battery aggregators to prevent them from discharging too rapidly in response to a market price.

Both Edge and Grid DERMS need to perform multiple forecasting and optimization functions to execute the responsibilities above. Edge DERMS needs to ingest data from connected DERs and combine real-time data with historical data to forecast the amount of flexible capacity that is available to support real-time operations. It will also need to perform optimizations such as automatically grouping and dispatching devices and communicating control commands to DERs and OEMs to execute autonomous DER management functions. Grid DERMS will need to ingest capacity forecast information from Edge DERMS and then provide grid operators with aggregated forecasts.

Similarly, Grid DERMS will need to optimize both aggregated BTM and FTM DERs to deliver grid services requested by operators. Delivering these aggregated forecasts and optimized grid services will require close integration among utility software systems, Edge DERMS, Grid DERMS, DER OEMs, individual DERs, and DER aggregators. Similarly, both Edge DERMS and Grid DERMS will need to deliver near-real-time telemetry to grid operators so that they can understand what DERMS is doing at any given time. For an Edge DERMS managing many thousands of devices, with varying levels of data quality, this will likely require the use of estimation techniques to provide accurate aggregated telemetry.

## Settlement, Reporting, and Incentive Management

After DERMS has completed its real-time activities, the work of reporting on past DERMS actions begins. For SCADA-connected devices, Grid DERMS typically will get accurate telemetry data in a format that is similar to what utilities get from their conventional grid assets, and thus the settlement process is similar to what is used for conventional power plants.

For BTM DERs, Edge DERMS will need to collect finalized data from OEMs, aggregators, and devices and then compute performance metrics in a format that the utility can use to compensate DER aggregators and owners based on program rules. In some cases, this process will require integration between the Edge DERMS and meter data management (MDMS) or customer information systems so that data from each DER can be accurately connected to the right customer and calibrated based on settled meter data.

Grid DERMS likely will collect high-level statistical information from Edge DERMS about specific DERMS actions so that planners, operators, and program managers can see the combined impact of BTM and FTM DERs. However, Edge DERMS typically will host more detailed analytics for BTM program performance.

# Paying For and Implementing DERMS

Utilities face numerous competing infrastructure investment needs and options. The primary reason utilities should invest in DERMS is to build and operate VPPs to strategically optimize investments and limited utility capital. This VPP-centric vision may differ from past DERMS implementations focused on mitigating system risk from BTM, customer-site distributed generation.[18] DERMS solutions with a VPP focus offer offer a way to reduce the need to build low capacity factor grid infrastructure, allowing valuable resources to be deployed elsewhere more effectively.

Successful DERMS/VPP implementations may require establishing performance incentive mechanisms—like those tied to energy imbalance market participation—that motivate utilities to pursue these innovative options. In the absence of such incentives, utilities may not prioritize the adoption of DERMS solutions despite their ability to enhance system flexibility while reducing overall costs to customers, given competing objectives and system needs.

## DERMS Procurement and Implementation

Utilities should consider a phased approach to DERMS implementation that addresses immediate bulk grid concerns while laying the groundwork for future DERMS capabilities. By beginning with clear objectives and manageable projects–rather than attempting to build a comprehensive DERMS solution immediately–utilities can demonstrate value to stakeholders and gain practical experience to refine their approach for future phases.

Overly complex DERMS RFPs with detailed technical specifications may result in lengthy procurement processes and difficulty finding suitable vendors. This can delay the implementation of critical functionalities in a process that is already time intensive. For example, Table 1 shows a recent, publicly-available DERMS RFP schedule that included 13 steps over 8 months, with additional pre-RFP scope development and post-RFP program launch adding approximately 6 to 12 months to the total process. Any delays in this timeline driven by unrealistic or unnecessary technical requirements would significantly impact a utility's ability to respond quickly to changing grid needs.

**Table 1. Recent Utility DERMS RFP Example**

| Stage | Process | Steps |
|---|---|---|
| 1 | Pre-RFP Activities | ▪ Scope of Work Development<br>▪ Intent to Propose Form Submitted<br>▪ NDA Completed |
| 2 | RFP Distribution and Q&A | ▪ Release of RFP to Interested Vendors<br>▪ Bidder's Conference<br>▪ Deadline for Questions Related to RFP<br>▪ Responses to Questions Provided |
| 3 | Proposal Evaluation and Award | ▪ Deadline for Proposal Responses<br>▪ Evaluation of Proposals<br>▪ Invitations Issued to Finalists for Interview<br>▪ Interview of Finalists<br>▪ Evaluation of Finalist Proposals<br>▪ Project Award Announced<br>▪ Finalization and Acceptance |
| 4 | Post-RFP Activities | ▪ Program Launch |

Source: SEPA (2025).

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[18] Smart Electric Power Alliance (2025). Insights from PPL's DERMS Implementation.

A more adaptable strategy might include engaging with industry peers and vendors to understand current DERMS capabilities and focusing on immediate needs, such as implementing demand response programs to address rising peak demand. This approach allows for faster deployment of VPP capacity that can address bulk grid capacity issues in the short term and enable the deployment of more advanced distribution-focused capabilities later on.

By adopting a pragmatic, step-by-step approach to DERMS implementation, utilities can navigate the complexities of the evolving energy landscape while meeting the needs of regulators and customers.

To implement a successful DERMS strategy, utilities should adopt an incremental approach that begins with clearly defined problems, and then addresses additional problems in phases, rather than attempting to build a comprehensive solution immediately. Consider two hypothetical examples (shown below).

As illustrated in this hypothetical example, the best way to enable rapid progress toward enabling grid value is to initially build VPP capacity and Edge DERMS functionality that delivers bulk grid value while prioritizing customer needs and program adoption, before adding complex distribution-level capabilities.

This process will require increased collaboration, and the development of shared goals, across multiple utility teams. For example, demand-side management (DSM) teams will need to work with grid operations teams to develop business processes that enable DERMS to be used for both conventional bulk grid demand reduction use cases and also newer functionality in which DERs help to manage distribution network constraints. In some cases, team structures may need to change to address changes to planning and operational processes.

Some utility bring-your-own thermostat programs–like APS's Cool Rewards program–have already embraced this approach. APS initially developed its program to address system-level peak loads and has begun moving toward locational dispatch through deeper system integration and collaboration with its grid operations team.[19]

DERMS development should follow agile principles with simplified initial functional requirements focused on outcomes as opposed to complex technical specifications. The defining characteristic of this process is to value progress over perfection by building modular capabilities that can evolve, ensuring that customer experience remains central while steadily expanding technical sophistication and grid integration of DERMS.

### Hypothetical Example: A Tale of Two DERMS Implementations

Utility A and Utility B are both projecting rapid demand growth and need additional resources to address future generation, transmission, and distribution capacity constraints. Utility A decides that it needs a DERMS to solve these problems. It hires a consultant, who writes a 1,000-page RFP with detailed technical specifications, and then it goes through a multi-step regulatory approval and procurement process. After proceeding through the process, Utility A learns that there are no existing solutions that can meet the complex technical RFP specifications. And so, after the years-long process, it has not been able to take steps to use DERs to address its forecasted capacity challenges.

In contrast, Utility B speaks with several utilities and vendors to learn what is and is not possible today, and decides to start its DERMS journey by launching thermostat and battery demand response programs. It writes a concise RFP asking for program and technology combinations that will meet its need to address bulk grid capacity issues in a first phase, and will proceed to addressing distribution capacity issues in future phases.

Utility B launches a VPP program with Edge DERMS technology and builds tens of MWs of VPP capacity in the program's first year. In the following year, Utility B outlines several distribution deferral use cases that it would like to solve. Utility B demonstrates the feasibility of these use cases with its Edge DERMS provider, and then builds a Grid DERMS RFP based on those use cases. As a result, Utility B builds a sophisticated Grid + Edge DERMS solution that solves real-world problems incrementally, whereas Utility A is significantly delayed because of its complex RPF process and project requirements.

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[19] Arizona Public Service (n.d.). *Cool rewards.* Retrieved from https://www.aps.com/en/About/Sustainability-and-Innovation/Technology-and-Innovation/Cool-Rewards.

## Value Streams Resulting from DERMS

As DERMS investments grow, utilities will need to quantify the benefits that result from the investments. Some of these are relatively easy to quantify, like the value of avoided generation and transmission costs from peak load reduction, whereas others are more difficult, like situational awareness. An effective DERMS implementation strategy is to build incrementally based on more easily quantifiable outcomes, while working to quantify some of the more difficult ones (see Table 2).

As regulators increasingly recognize the value of DERMS and VPPs, the financial pathway for these investments should become clearer. An increasing number of utilities now have mechanisms to include DERMS and VPP implementation costs in electricity rates, provided these programs demonstrate cost-effectiveness. This regulatory evolution creates a sustainable funding model for grid modernization efforts that leverage distributed resources, incentivizing utilities to pursue these technologies.

**Table 2. Value Streams Resulting from DERMS**

| Quantifiable | Less Quantifiable |
|---|---|
| ▪ Avoided generation capacity requirements<br>▪ Asset management (e.g., preventing overload)<br>▪ Line loss reduction<br>▪ Voltage support/Ancillary services<br>▪ Frequency regulation<br>▪ Contingency reserve<br>▪ Energy arbitrage<br>▪ Generation capacity reduction | ▪ Improved visibility and situational awareness of DERs on the grid<br>▪ Overall distribution deferral value for a DER program<br>▪ Enhanced decision support tools<br>▪ More accurate forecasting and optimization to inform real-time operations |

Source: SEPA (2025).

## Gaps in Conventional Regulatory Structures

Regulatory structures may present significant barriers to DERMS investments. Utilities are allowed to recover costs and earn a rate of return on traditional utility capital expenditure projects, such as building new substations. Within most jurisdictions, software-as-a-service (SaaS) investments–including DERMS software for growing and managing VPPs–are treated as operations and maintenance expenses (O&M) that do not typically come with an earning mechanism. This asymmetry creates a fundamental disadvantage for DERMS expenses, as the costs required to establish DERMS capabilities must be justified without traditional earnings mechanisms.

A problematic timing mismatch also exists: O&M costs (in this case the DERMS costs) materialize on the balance sheet immediately while the quantifiable value streams accrue over time. This mismatch puts pressure on programs to show short-term event-specific impact great enough to justify the entire spend, while undervaluing system-level benefits accrued over time. These challenges create an opportunity for regulatory frameworks that provide an earnings mechanism that rewards utilities for building cost-effective alternatives to conventional infrastructure, even if the costs have a SaaS structure. Another approach would be to allow utilities to capitalize SaaS investments. The utility's ability to capitalize software-as-a-service investments is essential for achieving parity with traditional supply-side solutions, but current accounting principles may prevent this approach.[20]

At the same time, conventional demand-side management program budgets may prove insufficient to support the additional scaling of VPPs, as typical utility organizational silos limit the strategic growth of these resources. Possible solutions include allowing software expenses to be treated as capital expenditures instead of operational, performance incentive mechanisms, and recovering VPP and DERMS costs outside of DSM program budgets.

One potential solution to help resolve these gaps is to build a framework that quantifies the value of the benefits DERMS provides to utilities and, ultimately, its customers. Providing regulators with this information in a clear, concise format could help lead to better outcomes for utilities, vendors, and customers.

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[20] Advanced Energy United and Edison Electric Institute (2022). *Reaching for the Cloud: Solutions for Regulatory Parity for Cloud Services for Utilities.*

# Key Takeaways

- **Grid challenges are driving utilities to adopt DERMS.** Growing renewable energy generation, rising electricity demand, and decentralization of the grid are leading utilities to consider DERMS a critical tool to help manage DERs, provide multiple grid benefits, and reduce operational costs.
- **Utilities can invest in DERMS to build and operate VPPs to provide critical services.** VPPs are a proven, reliable solution for system-level peak load management. As utility programs grow, investments in DERMS allow utilities to manage multiple DER device types.
- **The effective management of DERs requires multiple, integrated software systems.** DER management requires both Edge DERMS (managing BTM devices) and Grid DERMS (integrated with utility OT and IT) because no single system can currently deliver all the benefits.
- **DERMS enables a new approach to utility operations**, providing enhanced visibility and decision-making for everything from long-term system planning to real-time daily operations.
- **There are multiple participation models for effectively managing DERs.** There is not a one-size fits all approach for effectively managing DERs. Utilities and grid operations can pursue utility-led, aggregator-driven, hybrid, or dynamic pricing approaches to DER management, each offering different advantages for capturing value from grid services.
- **Cost reduction is key, but DERMS provides multiple benefits.** DERMS benefits extend beyond peak load management and include difficult-to-quantify value streams such as improved grid visibility and situational awareness, better forecasting and optimization, and performance verification.
- **Outcome-based procurement is more effective.** To meet urgent grid needs DERMS RFPs should focus on a set of desired outcomes instead of an exhaustive list of overly complex technical specifications. Utilities and DERMS providers can innovate to deliver additional capabilities as DER programs grow.
- **Utilities should consider an incremental implementation approach.** No DERMS implementation can solve for all use cases on day one. A successful DERMS implementation should follow a gradual approach that begins by solving a limited number of clearly defined problems, initially building VPP capacity, and then expanding to additional use cases as programs expand and mature.
- **Regulatory evolution is needed to ensure efficient investments.** Regulatory conventions in some states may create disadvantages for DERMS/VPPs relative to traditional utility capital expenditure investments in generation, transmission, and distribution systems, particularly in how O&M costs are treated. New regulatory frameworks are needed that incentivize DERMS investments.

# Appendix: Definitions

**Advanced Distribution Management Systems:** A collection of applications including those typically associated with an outage management system (OMS), a distribution management system (DMS), and supervisory control and data acquisition (SCADA), designed to monitor, control, and manage operations and outages of a distribution network efficiently and reliably. ADMS functions can include automated fault location, isolation, and service restoration (FLISR); conservation voltage reduction, peak demand management; and volt/voltampere reactive (Volt/VAR) optimization.

**Demand Response Management System:** Management software that allows utilities to monitor, control, schedule, and manage a portfolio of DR programs and DERs, primarily load altering DERs such as hot water heaters, smart thermostats, and HVAC switches.

**Distributed Energy Resource:** a device that is connected within a utility distribution network (either in front of the meter (FTM) or behind the meter (BTM) and has the ability to deliver energy to the grid and/or can be managed to deliver grid services. This includes both devices that can deliver energy to the grid like batteries and BTM solar PV systems, and connected devices that can be managed to deliver grid services, such as smart thermostats, electric vehicles, electric vehicle supply equipment, or a C&I facility with demand response capabilities. Note that the definition is broader than the definition in Institute of Electrical and Electronics Engineers (IEEE) 1547, which requires that a DER be a "source of electric power…capable of exporting active power."[21]

**Distributed Energy Resource Management System:** Definition from IEEE 2030.11: "An application platform designed to manage device information, monitor and enable optimization and control of distributed energy resources (DER) and demand response (DR). A DERMS must be able to aggregate, simplify, optimize, and translate DER and DR functionalities. The DERMS enables the implementation of system services to the grid."[22]

**Energy Management System:** Provides the fundamental information and computation capability to perform realtime network analyses, provide strategies for controlling system energy flows, and determine the most economical mix of power generation, power purchases, and sales.

**Grid Services:** One or more grid resources are said to be delivering grid services if they are used to improve grid reliability, grid economics, power quality, and/or grid reliability. Examples include peak load management, load shift for energy arbitrage, ancillary services such as operating reserves and frequency regulation, or distribution network services like voltage management, distribution load management, and loss mitigation.

**Meter Data Management System:** A suite of software programs that receive and store meter data and support a host of revenue cycle and other functions (e.g., billing, outage management, and distribution engineering).

**Outage Management System:** Computer-aided systems that are used by electrical distribution systems. They are primarily used by the grid and distributed system supervisors to return power to the grid. Outage management systems identify outages and provide instant alerts.

**Virtual Power Plant:** From DOE's VPP Liftoff Report: "VPPs are aggregations of DERs that can balance electricity demand and supply and provide utility-grade grid services at scale."[23]

**Supervisory Control and Data Acquisition:** A computer-based system for gathering and analyzing real-time data to monitor and control equipment that deals with critical and time-sensitive materials or events.

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[21] IEEE (2018). Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces, in IEEE Std 1547-2018 (Revision of IEEE Std 1547-2003) , vol., no., pp.1-138, 6.

[22] IEEE (2021). Guide for Distributed Energy Resources Management Systems (DERMS) Functional Specification, in IEEE Std 2030.11-2021 , vol., no., pp.1-61.

[23] U.S. DOE (2023). Virtual Power Plants - Pathways to Commercial Liftoff. Retrieved from: https://liftoff.energy.gov/vpp/.

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