



CURRENT
ENERGY GROUP

Distributed Capacity Procurement Framework

**Addressing Grid Needs
Affordably and Reliably with
Distributed Energy Resources**

Prepared for the Solar Energy Industries
Association®



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Executive Summary

An Electric System Increasingly Under Pressure

Customers and utilities alike are experiencing persistent pressure caused by affordability challenges, booming electricity demand, and an aging grid. Default solutions to these issues are capital-intensive and driven by a system that incentivizes new infrastructure based on centralized planning and utility-owned infrastructure. Coupled with load growth and aging infrastructure, this results in an intense cycle of rising costs and construction of large-scale, centralized resources. Often, formal consideration of market-based or competitive alternatives that can provide modular, scalable resources at lower costs either does not exist or is relegated to ad hoc processes. **These pressures reinforce one another: load growth drives capital spending, capital spending drives rates, and rate pressure narrows the room for the next round of investment.**

Distributed Resources as a Competitive, Scalable Solution

Breaking this cycle requires a different approach to how grid needs are identified and met.

Distributed energy resources (DERs) are well positioned to respond to load growth, aging infrastructure, and climbing energy bills. To harness their potential, DERs need to be on an equivalent footing with traditional energy solutions. There is a range of DER technology configurations that can meet these objectives, providing service to the grid when and where it is needed. The distributed, modular, and scalable nature of DERs means that assets can be placed at locations on the grid on faster timelines where they will provide the most benefit. This can include providing capacity and energy to the broader grid, managing peak energy demand, and even deferring or avoiding infrastructure expenses altogether.

The Opportunity

Capturing that potential depends on three conditions: customers and third-party owners need enough revenue certainty to invest; DERs need a defined route to provide grid services rather than an ad hoc one; and planning needs to inform where and when DERs are deployed. Few jurisdictions have put all three in place. Existing system planning processes and procurements at the distribution level in most jurisdictions lack a structured alternative to default utility-owned, capital-intensive solutions. **The Distributed Capacity Procurement (DCP) Framework outlines the opportunity to use a comprehensive set of strategies to procure DERs and to challenge conventional approaches to resolving issues on the grid.**

Distributed Capacity Procurement Framework

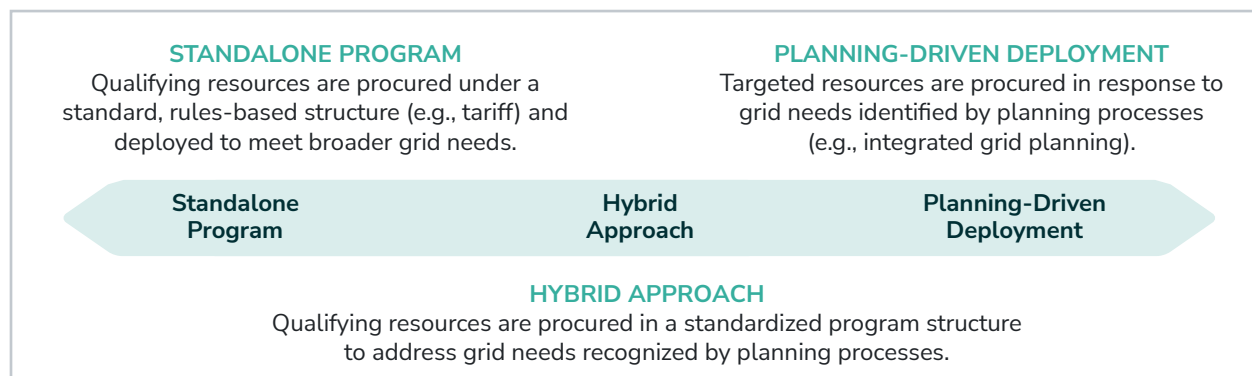
The DCP Framework is offered as a comprehensive approach to meeting grid needs across a variety of use cases. The three pathways give regulators and utilities a structured way to match a DER procurement mechanism with the grid need at hand, using the level of planning information a jurisdiction already produces. The pathways are ordered from least to most prescriptive, with respect to system needs and grid services, and a jurisdiction can operate more than one simultaneously. Identifying grid needs is central to determining which pathways apply in each circumstance; however, a jurisdiction with less sophisticated planning processes can still realize meaningful value from using the framework. Each pathway is not exclusive to the others. For example, DER deployed through Pathway 1 to provide capacity could also provide additional, locationally specific grid services through Pathway 2, provided that dual participation is appropriate.

- **Pathway 1 (Programmatic Tariff-Based Procurement)** seeks to support the broader system needs, primarily through energy and capacity grid services, while also enabling an opportunity to defer costly infrastructure investments.
- **Pathway 2 (RFP-Informed Programmatic Tariffs)** applies when planning identifies a category of recurring grid need that a standing tariff can serve. Competitive solicitations, such as requests for proposals (RFPs), set and periodically recalibrate tariff rates, but the tariff itself is the procurement mechanism. Pathway 2 pairs the scalability of Pathway 1 with market-informed pricing.
- **Pathway 3 (Competitive Solicitation)** is applied in specific circumstances where a standardized tariff is impractical. Discrete grid needs are identified through planning, solutions are narrowly defined and competitively procured, and, in exceptional and bounded circumstances, the pathway permits utility ownership.

Distributed Resources Meet Critical Grid Needs at Every Stage

Utility planning processes enhance the effectiveness of DER deployment, but they are not the deciding factor in achieving a more affordable, reliable, and cleaner grid. The pathways can bolster the resources available to respond to growing loads and provide an inexpensive, speedier reaction to infrastructure needs. All jurisdictions have system planning processes, stakeholder perspectives, policy frameworks, and incentive tools that can identify progressively specific grid needs. Accordingly, the DCP Framework reflects this continuum of planning and utilizes a DER procurement and integration approach determined by the specificity of the grid need, meeting broader service requirements with independent, programmatic structures and more targeted demands with planning-driven deployments.

Figure 1: The Program-to-Planning Continuum



A Better Path Forward

An affordable, reliable transition requires regulators, utilities, and customers to use every cost-effective tool available. The DCP Framework is intended to meet that need. It starts with the grid needs that a jurisdiction's planning processes already identify and offers a structured alternative to the default of traditional, utility-built infrastructure. **The DCP Framework can be implemented through procurement pathways that are transparent and grounded in core principles, informed by each jurisdiction's unique characteristics and context.** These principles, centered on planning requirements, tariff and procurement review and approvals, ratemaking and cost recovery, and measurement and verification, are present in most jurisdictions and require deliberate, coordinated application across existing planning, tariff, and ratemaking proceedings.

Context Setting

I. The Challenge: An Electric System Increasingly Under Pressure Converging Pressures on the Electric System

Rising demand drives rising costs.

Electricity demand is rising nationwide.¹ Load growth from electrification, data centers, and new large loads requires infrastructure investment. That investment drives rate increases, which in turn impact affordability. National retail electricity rates have experienced considerable growth over the past several years. Since 2019, nominal average retail power prices have increased by 29% for all customer classes, with more than 5% growth in the prior year alone.² Although utility bills as a proportion of income have generally trended downward for residential customers, as of May 2025, one-in-six U.S. households were behind on energy bills. Portions of the Pacific and Mid-Atlantic regions experienced the greatest increase in customer energy burden between 2019 and 2024.³

Anticipated load growth as a result of new large loads and building and transportation electrification following an era of flat load growth is now forcing utilities to update their resource and infrastructure plans to accommodate this rapid increase in power demand. By 2030, new large loads could account for more than half of increasing energy demand, but the magnitude of these forecasts has been a significant source of uncertainty in utility load forecasts.⁴ Recent evaluations of utility load forecasts estimate that the energy needs of some new large loads could be overstated by 40%. This ambiguity creates a risk that utilities are building and maintaining grid infrastructure for load that may not materialize.

These new large loads, often concentrated in specific regions of the country, require substantial new investment in energy resources and expect quick interconnection timelines, often much faster than a utility can accommodate. According to surveyed utilities and power providers, lead times for delivering requested power will run almost two years longer than data centers expect.⁵ Providing energy at the scale and timeframes new large loads require challenges conventional utility resource planning and procurement processes. This creates an opportunity for distributed assets such as solar, storage, and flexible demand, resources sited close to where energy is consumed, to fill the gap. Interest in “bring-your-own-capacity” arrangements, in which a large load brings or funds dedicated resources as a condition of service, is also growing; the procurement pathways described in this paper apply equally to resources deployed under those arrangements.

¹ *Annual Energy Outlook 2026*, (U.S. Energy Information Administration, April 8, 2026), Electricity, <https://www.eia.gov/outlooks/aeo/narrative/index.php#Electricity>.

² Ryan Wiser et al., *Retail Electricity Price Trends and Drivers: Data Update-2026 Edition*, (Lawrence Berkeley National Laboratory, July 2026), 6, https://emp.lbl.gov/sites/default/files/2026-07/Retail%20Price%20Trends_2026%20edition_JulyUpdate.pdf.

³ Wiser et al., *Retail Electricity Price Trends and Drivers: Data Update-2026 Edition*, 16-17.

⁴ *Power Demand Forecasts Revised Up for Third Year Running, Led by Data Centers*, (Grid Strategies, November 2025), 3-4, <https://gridstrategiesllc.com/wp-content/uploads/Grid-Strategies-National-Load-Growth-Report-2025.pdf>.

⁵ *2026 Data Center Power Report*, (Bloom Energy, January 2026), 7, <https://www.bloomenergy.com/wp-content/uploads/2026-power-report.pdf>.

Aging infrastructure meets increasing stress.

The distribution system was not designed to deal with modern-day stressors. Equipment that is already at or near the end of its useful life is being asked to handle higher peak loads, bidirectional power flows, and more frequent extreme weather events. Each of these challenges requires greater system investment to ensure reliability. The result is rising cost without a corresponding improvement in reliability. On average, the power lines and transformers that comprise the grid are over 25 years old.⁶ A segment of investor-owned utilities reported that close to 90% of their distribution grid investments in 2025 were driven by adaptation, hardening, and resilience improvements, or replacements to system infrastructure.⁷

Reliability investment further pressures affordability.

Utility spending on grid hardening, vegetation management, storm restoration, and asset replacement is a growing component of rate increases in many jurisdictions. The more the grid degrades, the more it costs to maintain, and those costs are passed on to customers who are already under affordability stress. Distribution system spending increased by 5% on average per year between 2019 and 2025, and between 2024 and 2025, customers in at least 22 states saw price growth driven in significant part by distribution costs.⁸ These affordability challenges are compounded by the growing frequency of major events that affect electric service, such as severe weather, extreme heat, and extreme cold, which are leading to longer and more frequent power outages.⁹ Despite increasing distribution system expenditures and utility efforts to maintain reliability, in 2024, electricity customers experienced more than 11 hours in average total annual service downtime, a 45% increase compared to 2020.¹⁰

The modern grid has more tools than ever; the challenge lies in using them.

Topics that were once on the fringes of energy industry dialogue—dispatchable, small-scale generating resources, advanced distribution management systems, and other innovative energy technologies—are now available and capable of rivaling the price points and timeframes of conventional approaches to grid modernization. Coupled with ongoing generation retirements, ambitious energy policies, and accelerating load growth, the grid must leverage all available solutions to ensure affordability, reliability, and resiliency for all customers. Distributed resources can be deployed at the location, time, and scale required to maintain an affordable and resilient electricity grid; however, utility planning processes and rate design often fail to fully integrate and account for the benefits of these grid-edge and grid-forming technologies.¹¹

⁶ Cara Kuuskvere and Weston Dengler, “Aging US Power Grid: Navigating Toward Modernization,” Smart Electric Power Alliance, September 19, 2024, <https://sepapower.org/knowledge/the-aging-us-power-grid-navigating-toward-modernization/>.

⁷ *Adaptation, Hardening, and Resilience (AHR)*, (Edison Electric Institute, 2025), <https://www.eei.org/-/media/Project/EEI/Documents/Issues-and-Policy/Finance-And-Tax/Adaptation-Hardening-Resilience.pdf>.

⁸ Wiser et al., *Retail Electricity Price Trends and Drivers: Data Update-2026 Edition*, 26, 31.

⁹ Meris Lutz, “Power outages getting longer as extreme weather takes larger toll, report says,” Utility Dive, November 17, 2025, <https://www.utilitydive.com/news/power-outages-extreme-weather-jd-power/805658/>.

¹⁰ Table 11.1 Reliability Metrics of U.S. Distribution System, Data set (U.S. Energy Information Administration, October 2025), https://www.eia.gov/electricity/annual/html/epa_11_01.html.

¹¹ Ashtin Massie et al., “Grid-Scale Virtual Power Plants are Here. Have Utilities Noticed?” RMI, May 14, 2026, <https://rmi.org/resources/grid-scale-virtual-power-plants-are-here-have-utilities-noticed/>.

Conventional Approaches Compound the Challenge

The conventional distribution system investment model—centralized planning, utility-owned infrastructure, capital-intensive solutions—has not kept pace with these converging pressures and, in some respects, contributes to them.

Capital bias creates a structural preference for capital-intensive, utility-owned solutions.

Investor-owned utilities earn a return on capital investment and are responsible for operating a reliable grid that serves all customers. As load growth accelerates and infrastructure ages, utilities have a substantial opportunity to generate earnings by continually investing in network expansion and upgrades. This creates a financial incentive to build new infrastructure rather than procure lower-cost alternatives—even when those alternatives would deliver equivalent or superior grid performance at lower cost to customers. The larger and more capital-intensive the solution, the more the utility stands to earn. This expands the range of investment opportunities where capital bias can influence utility solutions to infrastructure challenges. Without a framework that systematically and fairly evaluates alternatives to traditional poles-and-wires infrastructure, the default outcome is a larger, more expensive grid that customers must pay for through rates.

Traditional planning and dispatch leave distributed resources on the sidelines.

Conventional grid operations rely on a centralized model: a single operator dispatches utility-scale resources and makes decisions about grid configuration with minimal visibility into or coordination with smaller-scale resources located on the distribution system. This means that existing distributed capacity—rooftop solar, batteries, flexible loads, and front-of-the-meter, distribution-connected solar, or battery energy storage systems (BESS)—is largely invisible to system operations and excluded from planning, even where it could meaningfully contribute to system needs. The planning outcome is equally consequential. Traditional distribution system planning employs a top-down approach where the utility prescribes the grid configuration needed to meet forecasted load, typically with minimal consideration for the existence, potential, or cost-effectiveness of customer-owned or third-party resources. The result is a planning process prone to undercounting available resources and overbuilding infrastructure.

The status quo forecloses competitive alternatives before they can be evaluated.

In the absence of a structured framework for identifying where distributed resources could meet grid needs, the default is capital-intensive, utility-owned solutions that place upward pressure on retail electricity rates. In many jurisdictions, competitive alternatives are never formally evaluated against the conventional wires solution, so the wires solution proceeds by default rather than on the merits. Where competitive markets have been enabled, they have demonstrated the ability to drive down prices through transparent price discovery while also fostering innovation in technology, business models, and service delivery.¹²

¹² Brian Martucci, “Virtual power plants helped save the grid during heat dome,” (Utility Dive, July 16, 2025), <https://www.utilitydive.com/news/virtual-power-plants-helped-save-the-grid-during-heat-dome/753247/>; “GMP’s Growing Stored Energy Network Delivers \$6M in Savings During July Heat Wave and Provides Lasting Year-Round Benefits for Customers,” (Green Mountain Power, July 28, 2026), <https://greenmountainpower.com/news/gmps-growing-stored-energy-network-delivers-6m-in-savings-during-july-heat-wave/>; “GB cements status as world leader in energy flexibility with estimated £300m savings for billpayers,” Energy Networks Association, June 26,

II. The Opportunity: Distributed Resources as a Competitive, Scalable Solution

Breaking the cycle of rising costs, worsening reliability, capital-biased system planning, and consolidated control requires a fundamental shift in how we approach these issues. Distributed energy resources (DERs) are well positioned to respond to load growth, aging infrastructure, and climbing energy bills. Harnessing their potential requires proactive policy to put DERs on an equivalent footing with traditional energy solutions in grid access and utility planning.

Definitions and Technology Landscape

A “distributed energy resource” (DER) is a distribution system-connected device or technology that can interact with the electric grid.¹³ DERs are usually small- or medium-scale technologies that can accomplish some combination of generating, storing, or reducing electricity usage at a home or a business, or may solely provide energy and services to the grid at large. Depending on the technology type, a DER may be interconnected to the grid in a manner that allows for injection and consumption of electricity from the system in a “bidirectional” flow.

Typical technologies include solar energy systems, battery energy storage systems (BESS or ESS), solar-plus-storage configurations, electric vehicle charging infrastructure, and demand response resources. A DER can be connected to the grid as either a “front-of-the-meter” (FTM) or a “behind-the-meter” (BTM) resource. FTM resources are usually connected directly to the distribution grid on the utility side of a meter, while BTM resources are usually located at a customer’s site and are on the customer’s side of the meter (co-located with load). BTM DERs and FTM systems can be combined and operated as a single, cumulative energy resource, also known as a “virtual power plant” (VPP) by a third-party aggregator that participates directly in the market on behalf of the DER portfolio.

The Case for Distributed Resources

DERs differ from traditional infrastructure in ways that matter for the challenges described above: they can be deployed incrementally, at the location where a need exists, on shorter timelines, and often at lower cost, and a single asset can provide more than one grid service.

- 1. Cost-Effectiveness and Affordability:** DERs deployed on circuits with available hosting capacity typically require reduced interconnection upgrades and are capable of avoiding the most expensive components of traditional infrastructure investment, thereby improving utilization of existing network assets and lowering costs for all customers.¹⁴ When procured competitively and dispatched during peak load conditions, DER portfolios can cost less than the capital projects they defer or displace.¹⁵

2025, <https://www.energynetworks.org/newsroom/gb-cements-status-as-world-leader-in-energy-flexibility-with-estimated-gbp-300m-savings-for-bill-payers>.

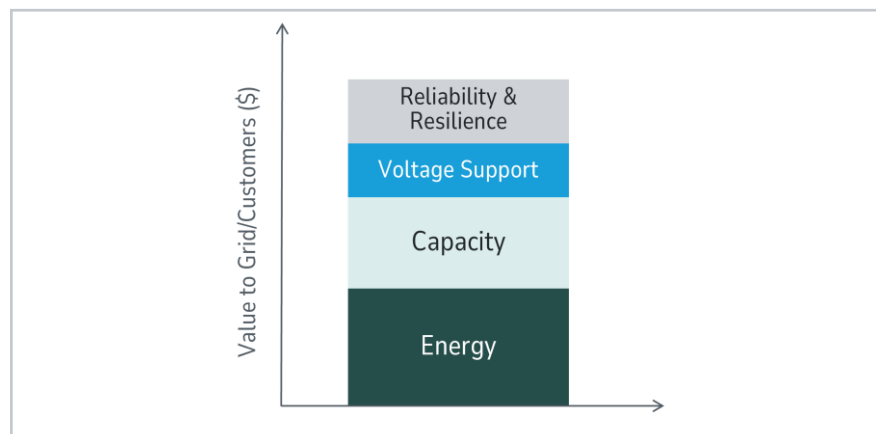
¹³ “Distributed Energy Resources,” California Energy Commission, n.d., <https://www.energy.ca.gov/data-reports/california-energy-planning-library/distributed-energy-resources>.

¹⁴ Brian Martucci, “Better grid utilization could save customers \$170B: Brattle report,” Utility Dive, March 23, 2026, <https://www.utilitydive.com/news/better-grid-utilization-could-save-customers-170b-brattle-report/815436/>.

¹⁵ Ryan Hledik et al., *The Untapped Grid: How Better Utilization of the Power System Can Improve Energy Affordability*, (The Brattle Group, March 2026), <https://www.brattle.com/wp-content/uploads/2026/03/The-Untapped-Grid-Mar-2026.pdf>.

2. **Modular and Scalable:** DERs can be deployed incrementally, matched to the pace and geography of actual load growth, rather than requiring large, discrete (“lumpy”) capital commitments sized to meet forecasted peak demand years in advance.¹⁶ This reduces the risk of overbuilding and allows the power system to adapt as conditions change.
3. **Speed to Deployment:** DERs can typically be deployed on timeframes measured in months, not years—a critical advantage in an environment where new large loads are requesting interconnection faster than traditional infrastructure can be built.¹⁷ This, in turn, can support local economic development by accommodating large-load integration, rather than those same loads seeking grid integration elsewhere.
4. **Locational Precision:** DERs can be incentivized or directed to site at the exact location where the grid needs exist—on the constrained feeder, behind the overloaded transformer, at or near the substation approaching capacity—rather than relying on a remote, centralized resource to manage local conditions.¹⁸
5. **Multi-Service Capability:** A single DER asset or portfolio can provide several system benefits, including capacity, energy, voltage support, reliability, and resilience services at once—delivering more value per dollar than single-purpose infrastructure.¹⁹
6. **Grid Utilization and Bulk System Synergies:** Scaled distribution-connected storage deployed within a localized load constraint can both lower peak demand on the surrounding transmission system and increase that system’s utilization by charging batteries during off-peak hours—creating natural synergies between distributed and bulk-scale resources and system upgrades.²⁰

Figure 2: Illustrative Example of Value Provided by DERs



¹⁶ *Solar Integration: Distributed Energy Resources and Microgrids Basics*, (U.S. Department of Energy, n.d.), <https://www.energy.gov/cmei/systems/solar-integration-distributed-energy-resources-and-microgrids-basics>.

¹⁷ Barbara Lantz, “Fast, Efficient Solutions to Meet Electricity Demand Growth,” RMI, February 18, 2026, <https://rmi.org/resources/fast-efficient-solutions-to-meet-electricity-demand-growth/>; “2026 Data Center Power Report,” 7.

¹⁸ Kevin Brehm and Mary Tobin, *Virtual Power Plant Flipbook*, (RMI, November 2025), 11, https://rmi.org/app/uploads/dlm_uploads/2024/07/VP3_flipbook_v1_3.pdf.

¹⁹ Paul De Martini, *Bulk Power, Distribution, and Grid Edge Services Definitions*, (U.S. Department of Energy, November 2023), https://www.energy.gov/sites/default/files/2023-11/2023-11-01%20Grid%20Services%20Definitions%20nov%202023_optimized_0.pdf.

²⁰ Hledik et al., *The Untapped Grid: How Better Utilization of the Power System Can Improve Energy Affordability*.

Third-Party Ownership Supports Capturing DER Potential

Realizing the full value of distributed resources requires that the entities best positioned to innovate, compete, and serve customers—third-party developers and customers themselves—have confidence that they can invest in DERs, help support the grid, and receive fair compensation for doing so. This requires clearly defined roles.

- 1. Procurements That Facilitate Competition Can Lower Costs:** When third-party developers compete to provide DER-based grid services, the result can be pricing and value to customers that reflect market dynamics, rather than a utility's revenue requirement. Competitive procurement methods can lead to outcomes such as reduced risk to ratepayers, lowest price prevails, innovation, and expansive access, each of which drives down costs to customers.
- 2. Customer Access and Participation:** From the customer perspective, third-party ownership enables direct participation in the energy system—enabling customers to generate their own electricity, reduce their consumption, and contribute to grid reliability with BTM resources—regardless of their utility or jurisdiction. Similarly, customers that subscribe to FTM resources, like community solar, can reduce their consumption or energy bills and support overall system operations.
- 3. Opportunity for Targeted Benefits for Disadvantaged Customers:** Third-party ownership, when enabled through deliberate framework design, gives customers the opportunity to access DERs that might otherwise be out of reach for them. By giving low-income and disadvantaged customers direct access to DERs, these frameworks can deliver value directly to the households and communities that need it most by lowering energy bills and advancing equity outcomes.
- 4. Counterbalance to Capital Bias:** A framework that defaults to third-party ownership creates a structural counterweight to the utility's financial incentive to maximize capital investment. It forces the question: is a given grid need better met by a competitive, distributed solution or by traditional infrastructure?
- 5. Innovation and Market Development:** Third-party developers bring technological innovation, project financing, customer acquisition capabilities, and business model flexibility that utilities, as regulated monopolies, are structurally and experientially less positioned to provide. That innovation can improve the customer experience, enhance reliability, and lower costs.
- 6. Leverage Well-Established Expertise:** Depending on the jurisdiction, third-party developers may have more experience and expertise with distributed asset development and operations compared to a traditional utility.
- 7. Equitable Risk Allocation:** The traditional “cost-of-service” regulatory model allows utilities to recover their capital investments plus a rate of return on those expenditures. While this framework supports infrastructure development, it also means that ratepayers bear the financial risks associated with project execution. If a utility project faces cost overruns, technical failure, underperformance, or some combination of each risk, the utility still collects its regulated rate of return from ratepayers, and customers are responsible for covering the costs. In comparison, a competitive framework shifts construction, cost-overrun, and performance risk to developers, who are paid only for service actually delivered. Ratepayers still carry some risk—a tariff rate set too high, for example—which is why compensation design and periodic recalibration matter (Principles 5 and 10).
- 8. A Continuing and Critical Utility Role:** Third-party ownership does not diminish the utility's responsibilities for planning, interconnection, and dispatch coordination. Utility ownership of DERs is addressed as a bounded exception under Pathway 3.

The Gap: Procurement Mechanisms Have Not Kept Pace

Despite their demonstrated capability and cost-effectiveness, DERs remain underutilized, in part, because utility mechanisms for planning, procuring, and deploying distributed capacity at the distribution level are still immature. The result is a structural disconnect. Procurement frameworks that allow distributed capacity to compete with traditional infrastructure on the same terms—systematically, transparently, and at scale—do not yet exist in most jurisdictions. In the absence of clear pathways to leverage DERs, the default response to a distribution grid need remains traditional, utility-owned wires infrastructure—not because it is superior, but because structured alternatives have not been properly established. This is the gap that the Distributed Capacity Procurement (DCP) Framework is offered to address.²¹

III. DCP Framework: Procurement Pathways Overview

Pathway 1, programmatic tariff-based procurement, seeks to support the grid primarily through energy and capacity grid services, while also enabling an opportunity to defer costly infrastructure investments. Pathways 2 and 3 are targeted to a broader range of needs which may be procured through a tariff with compensation that is calibrated according to submitted project bids, or through a standard competitive solicitation process. Both Pathways 2 and 3 are related in that they are driven by planning, but they are distinguished by the level of precision required to address the involved grid need.

Each of these pathways is optimized to lean on planning processes to provide grid services where they are most needed, but any jurisdiction with basic or advanced planning processes can take advantage of the pathways.

Table 1: Overview of DCP Framework Pathways

Pathway	Procurement Type	Ownership	Technology Type	Grid Services	Compensation	Planning Relationship
Pathway 1: Programmatic Grid Services Tariff	Open enrollment; walk-up tariff; standardized rules	Customer or third-party ownership	BTM/FTM solar, storage, solar+storage, demand response (DR), VPPs	Capacity, energy arbitrage, renewable integration, avoided distribution, avoided transmission, avoided greenhouse gas emissions	Value-based determination and/or avoided cost	Standalone program Resource adequacy planning informed (not driven by distribution grid planning)

²¹ A note on terminology. “Distributed capacity procurement” has been used, including in Minnesota, to describe a utility-led model in which the utility procures and owns distributed storage sited at customer premises. This paper uses the term to reflect a more comprehensive and balanced approach, and to describe the full set of mechanisms by which distributed capacity can be procured, with third-party ownership as the default and utility ownership as a bounded exception. See, contra, *Distributed Capacity Procurement: Unlocking Grid Value with Utility-Led DER Deployment*, (Smart Electric Power Alliance, July 2025), <https://sepapower.org/resource/distributed-capacity-procurement/>.

Pathway	Procurement Type	Ownership	Technology Type	Grid Services	Compensation	Planning Relationship
Pathway 2: RFP-Informed Programmatic Tariffs	Grid services tariff with competitively calibrated rates	Customer or third-party ownership	FTM/BTM; technology-neutral	Full range: capacity, voltage, frequency, resilience, infrastructure avoidance	Program rates calibrated via competitive solicitation	Hybrid approach Distribution grid planning-driven: activated by identified grid needs
Pathway 3: Competitive Solicitation	Targeted RFP for site-specific needs	Third-party preferred; limited exceptions for utility	FTM; project-specific	Full range, including operational integration	Competitive bid, project specific, pricing	Planning-driven Specific need, location, timeline

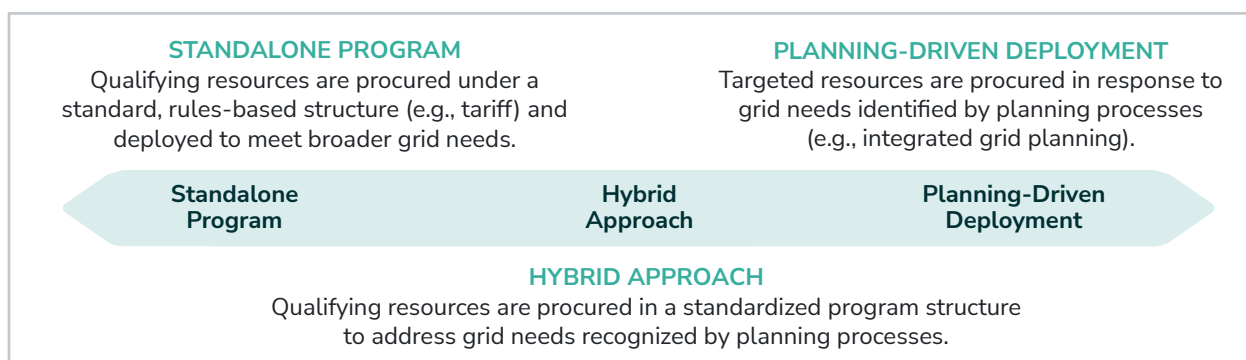
IV. Planning as the Basis for Identifying Grid and Power Supply Needs

Planning as a Key Input

The DCP Framework outlines practical mechanisms to meet needs identified by grid and power supply planning processes. Utility planning processes enhance the effectiveness of DER deployment, but they need not limit efforts to achieve a more affordable, reliable, and cleaner grid. System planning maturity, along with policy, incentives, and stakeholder input, drives the precision of grid needs, from broad, systemwide needs to highly granular needs bounded by location and time. DER procurement and integration methods fall along a spectrum, ranging from independent, programmatic approaches to planning-driven structures, with the specific grid need determining the optimal DER solution.

Expansive grid needs can be met through standalone, open-enrollment procurements of qualifying resources, such as those identified by resource adequacy planning processes. Power system planning processes that can identify more tailored grid needs can drive targeted DER procurement and deployment. A mid-point procurement approach relies on grid needs identified in planning processes to conduct standardized resource procurements. Figure 3 illustrates this progression of system planning parameters and ensuing resource procurement and deployment methods.

Figure 3: The Program-to-Planning Continuum



Building on the program-to-planning continuum, each pathway in the DCP Framework is defined by the grid need it addresses and offers an ordered structure for procuring and leveraging DERs that delivers customer access and participation, equitable risk allocation, and targeted, competitive solutions. Pathway 1 can serve as a default mechanism, reflecting standalone program design and offering the least-restrictive mechanism for meeting grid needs. Pathway 2 and Pathway 3 apply when the specificity of the grid need calls for more targeted procurement processes through their hybrid and planning-driven features, respectively.

Pathway 1 (Programmatic Tariff) is not directly dependent upon utility system planning, though effectiveness improves when it is integrated into resource adequacy and system infrastructure planning processes.

Pathway 2 (RFP-Informed Programmatic Tariffs) is informed by robust system planning as a critical input—clearly identified and transparent grid needs can help support the basis for and scale of procurement.

Pathway 3 (Planning-Driven, Competitive Solicitation) similarly relies upon comprehensive planning processes but is positioned to meet highly specific grid needs that are locationally and temporally discrete.

Connecting Planning to the Three-Pathway DCP Framework Approach

Jurisdictions with basic or advanced system planning processes can take advantage of the DCP Framework, sequencing implementation to match the trajectory of their planning capabilities. Initially, Pathway 1 can be established in response to resource adequacy needs, while Pathway 2 can be activated concurrently with planning improvements. Pathway 3 is reserved for needs that a standing tariff cannot practically serve, or where a Pathway 2 tariff has been offered without success.

Pathway 1: Not planning-driven, but planning-informed. Planning serves as an input to resource procurement but does not direct specific sourcing decisions. Designed to target savings for customers on forward capacity, energy arbitrage, and renewable integration, in addition to reducing consumption. Concurrently, the distribution system can benefit by altering peak demand and avoiding costly system upgrades to serve new or changing load. Operates as a standing market signal; locational price signals can reflect distribution grid planning data, but enrollment is continuous and open.

Pathway 2: Planning-driven. Activated when the power system planning identifies specific grid needs that can be met with targeted, scalable DERs.

Pathway 3: Planning-driven. Applied where a standardized procurement mechanism is impractical. Activated when specific, discrete grid needs are identified through planning processes and solutions are narrowly defined and competitively procured.

The pathways can bolster the resources available to respond to growing loads and provide an inexpensive, speedier reaction to infrastructure needs that appropriately compensates the value DERs provide to the grid.

DCP Framework

I. Pathway 1: Programmatic Tariff-Based Procurement

The first pathway enables customers and third-party developers to deploy DERs at scale through a standalone program. This baseline approach to scalable DER deployment allows resources to participate via a tariff-based mechanism which contains transparent price signals and standardized program rules. Solar and/or storage assets are most appropriate for this pathway. Compensation can be determined using an approach that establishes distinct values for each delivered grid service (“value stack”). Project compensation may also reflect other associated value streams to ensure that compensation matches fair value to the broader system and can evolve alongside changing grid needs.

This pathway can be deployed in nearly all jurisdictions. Enabling factors include the development of standardized interconnection and tariff frameworks, in addition to uniform performance and compensation policies for each procured service. Assured revenue streams are critical for maximizing project buildout, as they dictate the financing terms and risk profile of projects. This pathway is best utilized as a primary DER procurement mechanism and informed by resource adequacy planning, complemented by the targeted planning integration of Pathways 2 and 3.

Purpose and Rationale

Pathway 1 addresses a broad range of system challenges by building a robust foundation for DER procurement and deployment. It is informed by expected energy and capacity needs and can proactively build additional, latent flexibility into the system. Enumerated below, each objective can be achieved through a planning-informed program that translates broader grid needs into a standardized, transparent approach to DER integration.

- **Create a standing, market-accessible pathway** for third-party-owned DERs to provide energy and capacity to the distribution system while informing traditional planning processes.
- **Build up grid flexibility** with a portfolio of distributed resources that provide system-wide value tied to needs for forward capacity, energy arbitrage, renewable integration, avoided transmission costs, and other needs.
- **Address expected load growth** over a longer planning horizon by enabling continuous, incremental capacity additions.
- **Reduce dependence on large, discrete capital projects** to meet baseline capacity needs.
- **Establish transparent price signals** that allow the market to respond to system needs and offer more certain terms for project planning and financing.

Key Design Characteristics

The primary features of Pathway 1 support customers and third parties with accessible and clear mechanisms to deploy DERs in support of grid needs. Participation, compensation, and eligibility are broadly apparent and informed by utility planning processes.

- **Open Enrollment, Expansive Availability:** Not contingent on a planning cycle, RFP, or discrete procurement event
- **Tariff-Based Compensation:** Rates set administratively based on value delivered, avoided costs for grid services, other attendant value streams, and tied to specific performance

- **Long-Term Predictability:** Resources are assured of their performance requirements and revenue opportunities through agreements or other mechanisms that secure long-term project conditions
- **Third-Party Ownership:** Customer-owned and developer-owned resources; utility ownership is not contemplated under this pathway
- **BTM and FTM Eligible:** Both BTM and FTM resources can participate
- **Aggregation-Compatible:** Both BTM and FTM resources can be combined and operated as VPPs by third-party aggregators

Grid Service Values

Grid needs on the wider system are served by Pathway 1, enabling resources to meet energy and capacity needs, defer network infrastructure investment, or avoid it altogether.

- **Energy:** kWh injection, consumption reduction, renewable energy certificates, or storage during peak renewable output
- **Capacity:** kW contribution to system peak or local peak reduction
- **Load Modification:** Shifting or reducing demand in response to system conditions
- **Latent Generation Flexibility:** Dispatchable or responsive capacity available as system conditions evolve
- **Avoided Distribution Value:** Defer or displace traditional distribution infrastructure investment needs
- **Avoided Transmission and Other Bulk Power Expenses:** Defer or displace incremental high-voltage and bulk system capital expenses
- **Avoided Transmission and Distribution (T&D) Line Losses:** Diminished energy losses from electricity delivery across the power system

Compensation

Compensation in Pathway 1 recognizes delivered grid value and enables rapid, scalable deployment in support of power supply and system needs. This is achieved by deriving transparent compensation from both the avoidance of traditional infrastructure investment and granular benefits defined by the time and location of grid needs. Additional, performance-bounded incentives can be made available where needed to bolster deployment and grid support.

- **Value-Based Rates:** Rates built up service by service (a “value stack”) from avoided generation capacity, avoided energy, avoided T&D, avoided line losses, and other quantified value streams, each derived through a commission-approved avoided cost methodology
- **Time-Differentiated Rates:** Compensation varies by time of delivery to reflect temporal value
- **Location-Differentiated Rates:** Compensation varies by location of asset to reflect any locational value to the transmission and distribution grids within the utility’s territory
- **Deployment and Performance Benefit:** Incentive provided to new DERs that stipulates performance to support deployment and assure grid support

Relationship to Planning

Given Pathway 1 reflects characteristics of a standalone program, it is informed by integrated resource planning and resource adequacy needs for system-wide energy and capacity needs and for bulk power system cost avoidance. Procurement targets and program enrollment target levels

should be informed by resource adequacy planning to ensure deployed DERs meaningfully address grid needs without exceeding what is required.

Existing Pathway 1 resources must be reflected in utility transmission and distribution planning baselines. In addition, anticipated Pathway 1 deployment should be incorporated into forward-looking planning scenarios. Procurement targets and program enrollment target levels should be informed by resource adequacy planning.

Case Studies

The jurisdictions listed in Table 2 reflect Pathway 1 features in domestic and international energy systems.

Table 2: DER Programs with Pathway 1 Characteristics

Jurisdiction	Program	Notable Pathway Feature
Maryland	Community Solar ²²	Delivers renewable energy to meet state energy needs through FTM solar DER.
New York	Value of DER (VDER) ²³	Facilitates the provision of time-differentiated energy and capacity from DERs to the regional energy market through an open-enrollment tariff structure.
Rhode Island	Proposed: Distribution-Connected Energy Storage Tariffs ²⁴	Rhode Island is currently developing two open-enrollment tariffs to facilitate ESS deployment to support retail and wholesale electricity systems. The tariffs are intended to support distribution system peak demand reduction and infrastructure investment deferrals.

II. Pathway 2: Tariff-Based Procurement with Competitive Price Discovery (RFP-Informed Programmatic Tariffs)

Pathway 2 is designed to address specific capacity and grid service needs as identified through power system planning processes, in addition to supporting the broader system. This includes grid needs that are recurring, scalable, or suitable for standardized DER configurations, and situations where a standing tariff can attract ongoing deployment within a defined geographic area.

Planning identifies a category of grid need—feeder-level capacity relief, substation peak reduction, or a persistent voltage problem, for example—and the commission establishes a technology-neutral grid services tariff to serve it. Competitive solicitations are used to inform and calibrate tariff rates, ensuring tariff compensation is market-aligned. Developers are incentivized to provide accurate pricing information that keeps tariff rates aligned with market conditions and protects project financial health. Once rates are set, the tariff operates as an open, scalable channel for DERs to deliver the identified grid services. Periodically updating those rates through competitive price

²² “Community Solar Program,” Maryland Public Service Commission, <https://psc.maryland.gov/regulated-utilities/electricity/renewable-energy/community-solar-program/>.

²³ “Value of Distributed Energy Resources (VDER),” Joint Utilities of New York, <https://jointutilitiesofny.org/distributed-generation/VDER>.

²⁴ “Docket No. 24-34-EL Development of Tariffs Applicable to Energy Storage Systems Connected to the Electric Distribution Systems,” State of Rhode Island Public Utilities Commission and Division of Public Utilities and Carriers, <https://ripuc.ri.gov/Docket%20No.%2024-34-EL>.

discovery gives regulators a tool for shaping DER procurement while keeping compensation reasonable for participating projects. To avoid the underbuild that a race-to-the-bottom solicitation can produce, the competitively discovered rate should sit within a value-based ceiling and a cost-of-service floor, and the tariff could carry capacity blocks that trigger an upward rate adjustment when a block goes unfilled. Both BTM and FTM resources are available in this pathway, with grid needs dictating primary technical performance requirements (technology-neutral).

Facilitating a Pathway 2 approach requires an enhanced utility planning process, such as distribution grid planning, and thoughtfully designed tariffs to procure resources and RFPs to inform compensation. This pathway can complement Pathway 1 by ensuring DERs are deployed where they are most needed on the grid.

Purpose and Rationale

Like Pathway 1, Pathway 2 meets several grid challenges by employing a standardized procurement mechanism, but is distinct in that it leverages more advanced system planning processes to effectively address these issues and incorporate increasingly sophisticated procurement features. This results in focused DER integration.

- **Address specific, identified grid needs** that emerge from power system planning
- **Ensure DER solutions are evaluated** on equal footing with traditional infrastructure when the system requires investment
- **Source the right DER** technology and configuration for the specific service the grid requires
- **Enable competitive price discovery** where administratively set rates may not reflect market costs. For jurisdictions where market rates may not be readily available, utilize transparent and thoughtful mechanisms to understand and approximate rates

Key Design Characteristics

Pathway 2 ensures that DERs are evaluated alongside traditional capital-intensive solutions when seeking to respond to challenges on the grid, and permits transparent, competitive procurements organized around the nature and specificity of the identified need.

- **Targeted Scope:** Eligibility and compensation tied to specific planning-identified needs and locations
- **Open and Scalable:** Meets precise grid needs that are recurring, scalable, or suitable for standardized DER configurations
- **Tariff-Based Compensation:** Rates for provided grid services set via competitive, informational solicitation process
- **Long-Term Predictability:** Performance requirements and revenue opportunities are assured through mechanisms that secure long-term project conditions
- **Third-Party Ownership:** Customer-owned and developer-owned resources; utility ownership is not contemplated under this pathway
- **BTM and FTM Eligible:** Both BTM and FTM resources can participate
- **Aggregation-Compatible:** Both BTM and FTM resources can be combined and operated as VPPs by third-party aggregators

Grid Services

In Pathway 2, DERs are procured to meet both broad and tailored grid needs as identified by power system planning processes. This full range of grid services includes:

- **Capacity:** Peak demand reduction, load relief
- **Energy:** kWh injection, consumption reduction
- **Voltage Support and Reactive Power:** Injection or absorption of reactive power to maintain distribution voltage within required tolerances at or near the location of need
- **Frequency:** Rapid adjustment of real power output or consumption in response to deviations in system frequency, supporting bulk system stability from distribution-connected assets (compensable at the distribution level primarily where the utility is the balancing authority or through pass-through of wholesale ancillary service revenue)
- **Power Quality:** Mitigation of localized waveform disturbances, including harmonics, voltage flicker, sags, and swells, through advanced inverter functions, maintaining clean, stable power delivery for customers on the affected circuit
- **Reliability:** Outage frequency and duration reduction, backup power
- **Resilience:** Ride through, island, or restore service during and after major events
- **Avoided Distribution Value:** Defer or displace traditional distribution infrastructure investment needs

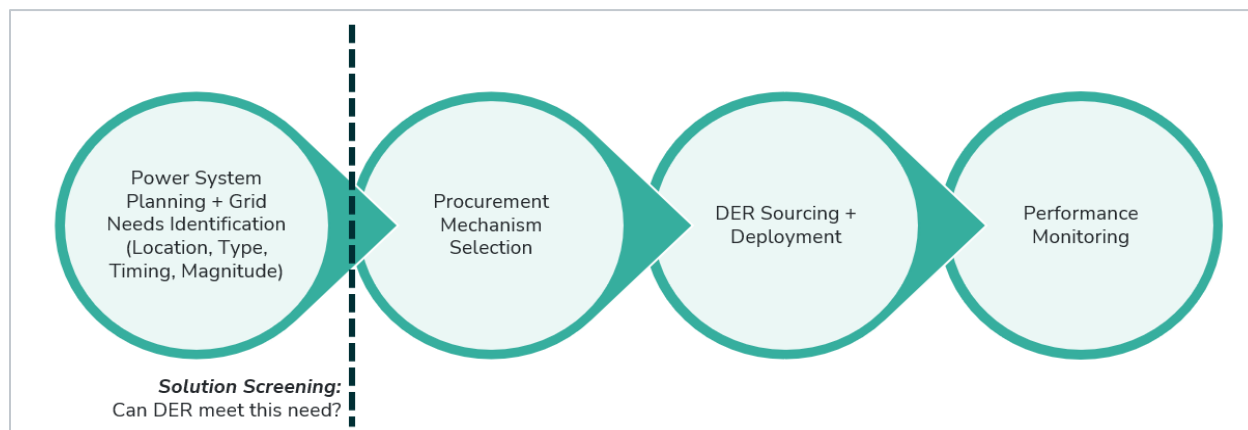
Compensation

Compensation can be informed by competitive discovery processes in Pathway 2, enabling tariff rates to reflect the cost to meet each articulated grid need and incorporate real market costs for developing projects. This can be accomplished through a competitive or informational solicitation and can encompass other value streams as appropriate.

Relationship to Planning

Pathway 2 is linked to identified grid needs and deploys DER solutions targeted to more sophisticated grid services, specific locations, and system conditions. Compensation and eligibility are tied to specific planning-identified needs and locations. The tariff is structurally similar to Pathway 1, but pricing is competitively informed, and the scope of provided services is narrowed to provide grid support at the location and time of greatest need. Pathway 2 does not narrow Pathway 1; it adds a locationally targeted channel alongside the standing service-territory-wide tariff offer. Indeed, DER participating in a Pathway 1 tariff could stack with complementary Pathway 2 tariff grid services, as eligible and appropriate.

Figure 4: The Planning-to-Procurement Pipeline



Case Studies

The jurisdictions listed in Table 3 reflect Pathway 2 features in domestic energy systems.

Table 3: DER Programs with Pathway 2 Characteristics

Jurisdiction	Program	Notable Pathway Feature
Connecticut	Shared Clean Energy Facility Program (SCEF) ²⁵	Program administrators use several data sources to set a price cap for program rates, including submitted project bids from prior program cycles, market conditions, and stakeholder comments. Projects are selected to provide energy and renewable energy certificates (RECs) through a reverse auction process.
Massachusetts	Solar MA Renewable Target (SMART) ²⁶	Secures capacity and environmental attributes from DERs to meet state resource adequacy and renewable portfolio standard objectives. Initial program implementation produced rates that required revision stemming from evolving policy and economic conditions which increased development costs without concurrent growth in program rates. The program administrator was subsequently granted authority to adjust SMART rates and procured volumes. Currently, program rates are calibrated according to an annual market survey and supplemental industry data.
United Kingdom	Flexibility markets ²⁷	Acquires time-differentiated energy, capacity, and additional grid service products through competitive tenders for location-specific needs.

²⁵ “Statewide Shared Clean Energy Facility (SCEF) Program,” Connecticut Department of Energy and Environmental Protection, <https://portal.ct.gov/deep/energy/shared-clean-energy-facilities/shared-clean-energy-facilities>.

²⁶ “Solar Massachusetts Renewable Target (SMART),” Commonwealth of Massachusetts, <https://www.mass.gov/solar-massachusetts-renewable-target-smart>.

²⁷ “Flexibility markets,” National Grid Distribution System Operator, <https://dso.nationalgrid.co.uk/flexibility-markets>.

III. Pathway 3: Competitive Solicitation (RFP-Based Procurement)

Pathway 3 is applied in specific circumstances where a standardized tariff is impractical. Under a Pathway 3 approach, planning processes identify a specific, discrete grid need (e.g., a particular substation requires 10 MW of load relief by 2029) and either the need is too discrete or too operationally specific for a standing tariff to serve, or a Pathway 2 tariff has been offered and has not attracted the required resources. A Pathway 3 competitive solicitation would then be conducted to acquire DERs that meet the need. Proposals are evaluated on cost, technical capability, and performance. Selected projects are contracted and deployed. This pathway is likely best suited for FTM resources.

Like Pathway 2, Pathway 3 is best employed where planning procedures are equipped to identify highly specific grid needs at precise locations, such as through a distribution system planning process. Pathway 3 is distinguished from Pathway 2 by the level of precision demanded of the deployed resources—Pathway 3 is designed to acquire DERs that meet bespoke, explicitly defined grid needs, whereas Pathway 2 procurements, although targeted, are technology-neutral and have a more expansive set of technological specifications.

Purpose and Rationale

Pathway 3 is designed to recognize there are specific circumstances and grid needs, as identified by advanced system planning processes, that require bespoke DER solutions, rather than replicable technological or resource configurations.

- **Address specific, identified grid needs** bounded by a specific location and timeline that emerge from power system planning
- **Enable rapid deployment** of resources to support critical grid needs while avoiding large infrastructure investments
- **Applied in highly specific circumstances** where a standardized tariff or DER solution is impractical or a tariff objectively fails to secure necessary grid services

Key Design Characteristics

Pathway 3 is designed for grid needs that are exceptional in their specificity and relies on a transparent, competitive solicitation to secure necessary resources.

- **Highly Specific, Tailor-Made Solutions:** Situations requiring bespoke solutions, specific technical requirements, or operational integration with existing utility infrastructure
- **Competitive Procurement, Utility-Owned in Narrow Circumstances:** Competitive solicitations function as the default procurement method, and in rare cases where a diligent RFP fails to secure the resources necessary to meet grid needs, utility ownership may be appropriate
- **Ownership:** Third-party owned and utility-procured (contracted service) as the preferred model. Utility ownership permitted in bounded circumstances

Compensation

Pathway 3 DERs are compensated through a competitive solicitation process that results in grid service contracts with the contracting utility. Proposals to the competitive solicitation are evaluated based on their costs, technical capabilities, and performance. Selected projects are contracted and deployed.

Grid Services

Grid services procured in Pathway 3 mirror those in Pathway 2, with enhanced operational integration with the relevant utility:

- **Capacity:** Peak demand reduction, load relief
- **Energy:** kWh injection, consumption reduction
- **Voltage Support and Reactive Power:** Injection or absorption of reactive power to maintain distribution voltage within required tolerances at or near the location of need
- **Frequency:** Rapid adjustment of real power output or consumption in response to deviations in system frequency, supporting bulk system stability from distribution-connected assets
- **Power Quality:** Mitigation of localized waveform disturbances, including harmonics, voltage flicker, sags, and swells, through advanced inverter functions, maintaining clean, stable power delivery for customers on the affected circuit
- **Reliability:** Outage frequency and duration reduction, backup power
- **Resilience:** Ride through, island, or restore service during and after major events
- **Avoided Distribution Value:** Defer or displace traditional distribution infrastructure investment needs

Relationship to Planning

In Pathway 3, specific, discrete grid needs, often bounded by location, time, or network infrastructure, are identified through planning processes and solutions are narrowly defined and competitively procured. Utility ownership is possible under this pathway, but it is only appropriate in specific, bounded circumstances with well-defined guardrails.

Utility Ownership: Bounded Circumstances and Guardrails

While third-party ownership and competitive procurement serve as the default across all three pathways, there are specific, bounded circumstances in which utility ownership of DER is the most appropriate model. Defining those circumstances with precision is essential to prevent utility ownership from becoming a blanket justification that crowds out competitive alternatives.

Infrastructure vs. Resource Distinction: For more than a century, the electric grid was unique among major modern commodity delivery systems because it often lacked embedded storage capability. As a result, electricity needed to be consumed at the same moment it was produced. This led to the creation of a system focused on meeting electricity demand during a limited number of peak hours over the course of the year. Natural gas systems include storage as core infrastructure—functioning as a “shock absorber” that decouples supply from demand and provides intrinsic operational flexibility. With the advent of scalable, dispatchable DER technologies such as BESS, this is now true in the electric sector.

When electricity storage is embedded in the grid’s architecture—located at key system interfaces and operated collectively—it can fundamentally improve grid resilience, dynamic stability, and stress absorption. Power storage can deliver primary and secondary real-time grid control in response to system conditions, as compared to dispatching a generation resource.

Assets functioning as grid infrastructure—analogue to transformers, capacitor banks, voltage regulators—are often the strongest candidates for utility ownership and rate-based recovery, although the same operational integration can often be achieved through a contracted service in

which the utility holds dispatch rights over a third-party-owned asset. However, third-party ownership of these grid infrastructure assets may be preferred in some circumstances. Assets functioning as energy or capacity resources, by contrast, should be competitively procured from third parties, for the same reasons jurisdictions have employed competitive bidding frameworks to inform procurement of grid-scale resources.

Bounded Circumstances for Utility Ownership

Listed below are the limited circumstances that may support utility ownership of DERs; however, this list is intentionally narrow and is expected to capture most situations in which such ownership is appropriate.

1. **Grid-embedded storage deployed as core infrastructure:** Storage sited at substations or key system interfaces as a component of broader infrastructure, where the asset is physically and operationally integrated with utility equipment and separating ownership would create operational fragmentation. Utility-operated for real-time grid control (sub-second to second timescales, integrated with supervisory control and data acquisition (SCADA) and distribution management system (DMS)), functionally equivalent to delivery infrastructure. These assets would not be dispatched for energy arbitrage or capacity market participation.
2. **Operational integration with grid protection and control systems:** Assets embedded in automated fault location, isolation, and service restoration (FLISR) schemes; DERs providing black start or islanding capability for utility-operated microgrids at critical infrastructure; assets co-located within utility substations requiring real-time coordination with protection relaying.
3. **Demonstrated market failure following a well-designed competitive solicitation:** Situations in which the utility has conducted a commission-approved, well-designed solicitation and the market has not produced viable bids. May occur in remote or low-density territories, locations with site-specific constraints, or very small-scale deployments where transaction costs exceed asset value. “Demonstrated market failure” requires evidence of the solicitation’s design, outreach, and results—a utility’s assertion alone would not be presumed sufficient.
4. **Emergency and time-critical reliability needs:** Post-event restoration where DERs are needed as an interim measure; rapidly escalating reliability degradation; interim bridge deployments while a Pathway 2 or Pathway 3 procurement is underway. Assets procured under this circumstance may be subject to a mandatory sunset/transition provision requiring re-evaluation within a defined period (e.g., three to five years).

Guardrails on Utility Ownership

Where utility ownership is identified as the best approach to meeting a grid need, that determination should be conservatively and thoughtfully bounded to balance meeting grid needs with capturing the full potential of DERs. The following principles are offered to guide utility ownership of DERs.

1. **Competitive Procurement First:** Except in emergencies, consider utility ownership only after a genuine solicitation process has failed to produce viable third-party alternatives. Solicitation design should be approved by the commission before issuance and, where practicable, administered or scored by an independent evaluator, so that a utility’s ownership interest does not shape the outcome.
2. **Independent Cost-Effectiveness Review:** All utility-owned DER proposals should be subject to independent analysis comparing them against third-party alternatives and the traditional infrastructure being displaced.

3. **Functional Separation and Conflicts of Interest:** Utility-owned DER should not participate in wholesale markets on terms giving the utility a competitive advantage over third-party participants.
4. **Cost Allocation and Conduct Rules:** Utility DER procurement, installation, and maintenance subject to code-of-conduct and cost-allocation rules, and to affiliate transaction rules where an affiliate is involved.
5. **Regulatory Pre-Approval:** Explicit regulatory approval required, including demonstration that the asset falls within a defined exception category.
6. **Sunset Provisions:** Emergency and interim deployments subject to re-evaluation for competitive replacement within a defined timeframe.
7. **Consistency with Existing Non-Wires Alternative (NWA) Frameworks:** Where a jurisdiction already has a non-wires alternatives process, the utility-ownership exception should be evaluated within that process rather than around it, so that utility-owned DER does not bypass an established competitive channel.

Case Studies

The jurisdictions listed in Table 4 reflect Pathway 3 features in domestic and international energy systems.

Table 4: DER Programs with Pathway 3 Characteristics

Jurisdiction	Program	Notable Pathway Feature
Colorado	Xcel Dispatchable Distributed Generation (DDG) ²⁸	Feeder-level local network needs are met by FTM DERs contracted through competitive solicitations facilitated by the utility. With oversight from the Colorado Public Utilities Commission, submitted bids are evaluated against a predetermined avoided cost value calculated by the utility. The utility is also permitted to submit self-owned projects to the solicitation.
Hawaii	Renewable Dispatchable Generation (RDG) ²⁹	Typically transmission-connected projects, the program is included as a Pathway 3 example because specific grid services, including grid-forming capacity, resilience, renewable energy, and dispatchable capacity, are secured through a competitive solicitation facilitated by the utility.
Minnesota	Xcel Capacity*Connect ³⁰	Leverages utility-owned FTM energy storage assets located at customer sites to provide energy and capacity to the regional energy market. The program reflects multiple pathways; however, the procurement mechanism is most closely associated with Pathway 3. Note: compared to the Xcel Colorado DDG program, this program defaults to utility ownership of DERs.

²⁸ “2026 PSCO Dispatchable Distributed Generation Request for Proposals,” Xcel Energy, <https://co.my.xcelenergy.com/s/renewable/developers/2026-psco-rfp>.

²⁹ “Competitive Bidding for System Resources,” Hawaiian Electric Company, <https://www.hawaiianelectric.com/clean-energy-hawaii/selling-power-to-the-utility/competitive-bidding-for-system-resources>.

³⁰ “Capacity*Connect,” Xcel Energy, <https://iprsoftwaremedia.com/418/files/202510/Info%20sheet%20-%20Capacity%20Connect.pdf>.

IV. Electric Grid Needs, Use Cases, and Procurement Mapping

The DCP Framework is offered as a comprehensive approach to meeting grid needs across a variety of use cases. Using planning results as a backdrop, the pathways permit regulators and grid operators to leverage DERs through procurement mechanisms that are most applicable to their respective jurisdictions. Each pathway can meet grid needs according to the planning horizon, ranging from years and months to minutes and seconds—growing load forecasts and climbing peak demand, which inflate bulk system needs for costly energy and capacity, can be met by low-cost, scalable, modular resources, in conjunction with using DERs to address more locational needs such as bolstering the reliability performance of aging infrastructure and supporting poor-performing circuits. Figure 5 illustrates a summary of the timescale system-planning results and ensuing grid needs. Figure 6 similarly outlines grid needs according to the involved system level. Appendix 2 provides detailed use cases and the relevant pathway for meeting each grid need.

Figure 5: Timescale of Grid Needs

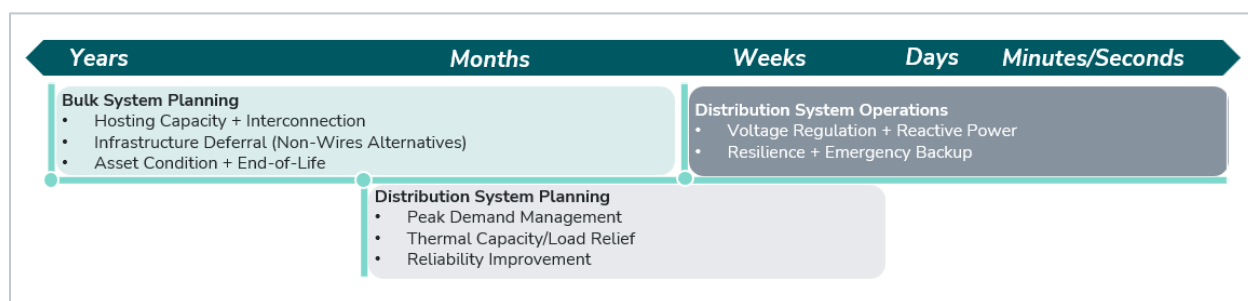
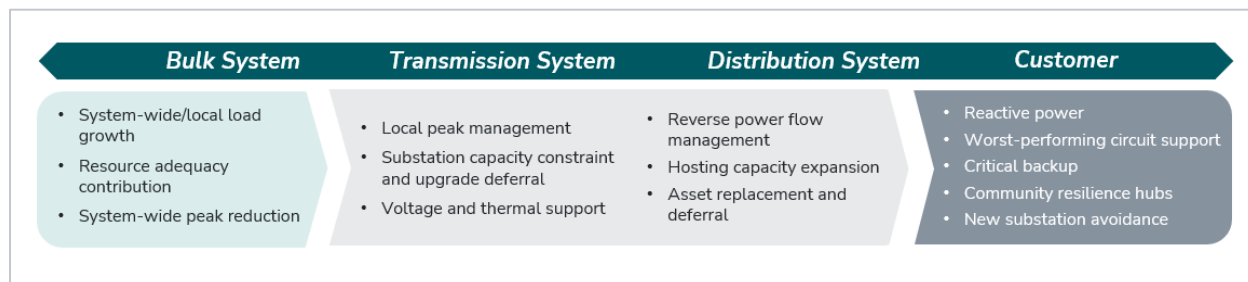


Figure 6: Taxonomy of Grid Needs



V. Incorporation in System Planning

To realize the full value potential for procured DERs, these resources should function as both inputs to and outputs of utility system planning. Where DERs have a direct impact on customer load and the customer's net grid energy, DERs can place downward pressure on utility load forecasts. This diminishes resource and infrastructure costs to customers because it reduces both the volume of energy demand that utilities must plan for and the capacity they must build to meet it.

Following completion of system planning processes, each pathway enables utilities to leverage best-fit DERs as “non-wires alternatives” for new or expanded grid infrastructure needs. Where DERs are lower-cost and faster to deploy than the wires alternative, they can accommodate new

load at lower cost and help utilities avoid the costs of building and maintaining distribution and transmission infrastructure on a faster timescale than traditional utility responses to load growth.

Additional system planning processes, such as those conducted at the sub-regional or regional grid level, can harness aggregated DERs to deliver resource adequacy (capacity) and low-cost, low-emitting energy to the local or regional grid. FERC Order 2222 permits aggregations of DERs to contribute to regional energy supply needs and directs the creation of pathways for DER market access and compensation.³¹ Jurisdictions, such as California, New York, and PJM, are utilizing this directive to integrate DERs with regional energy markets, recognizing that DER participation in wholesale markets can deliver valuable services to broader energy systems.³²

VI. Distinction Between Vertically Integrated and Restructured Markets

The DCP Framework can be applied to vertically integrated and restructured electricity markets alike. Utilities in a vertically integrated market generally provide all components of electric service, from generating electricity to transmitting and delivering it to the customer's site.³³ In a restructured electricity market, utilities typically only handle delivery of electricity, while third-party suppliers handle power generation. That retail distinction, however, is only one of two structural features that shape how the framework operates. The second is whether the utility sits inside a regional transmission organization (RTO) or independent system operator (ISO), where energy products and capacity are priced and transacted in organized wholesale markets. The two are independent: a vertically integrated utility in an RTO/ISO, like MISO or SPP, is both vertically integrated at retail and a wholesale market participant. Retail structure determines who coordinates DER procurement with planning; meanwhile, RTO/ISO membership prices the DER's delivered energy and capacity value, which determines how it reaches the DER owner. Although these distinctions can introduce some complexity to implementing the DCP Framework, jurisdictions in every combination can rely on their existing market structures to procure and integrate DERs.

Retail Structure, Who Coordinates Procurement: In a vertically integrated market, coordinating DER procurement with system planning is administratively simpler. The utility is the sole facilitator and procurer of generation and system resources, and this consolidation of grid need identification, procurement, and deployment streamlines DER integration across all three pathways. Restructured retail markets may face greater administrative and technical burdens, since DER coordination must occur across functions split among the distribution utility, competitive retail suppliers, and, in most cases, the regional system operator. The distribution utility remains the natural procurer of

³¹ "FERC Order No. 2222 Explainer: Facilitating Participation in Electricity Markets by Distributed Energy Resources," Federal Energy Regulatory Commission, September 25, 2025, <https://www.ferc.gov/ferc-order-no-2222-explainer-facilitating-participation-electricity-markets-distributed-energy>.

³² Note that DER participation in some areas has been limited, and several RTOs have FERC Order 2222 compliance dates that extend into the late 2020s. "FERC Order 2222 & DER Policy and Implementation Report," (Collaborative Utility Solutions, January 2026), <https://cuswebsite.blob.core.windows.net/2222tracker/Tracker-Report-January-2026.pdf>; Richard Zdunkewicz, "Virtual power plants in action: How rules and markets enable (or block) aggregation," PV Magazine, July 10, 2025, <https://pv-magazine-usa.com/2025/07/10/virtual-power-plants-in-action-how-rules-and-markets-enable-or-block-aggregation/>.

³³ "Electricity Markets – 101," National Governors Association, n.d., <https://www.nga.org/electricity-markets/>.

locational T&D value under the framework, but supply-side value must reach the DER owner through a different channel.

RTO/ISO Membership, Where Value is Priced: Outside an organized wholesale market, the energy and capacity value of a DER is defined by the utility's own avoided costs, established administratively through integrated resource planning and avoided-cost studies. Inside an RTO/ISO, that value is anchored to market outcomes. Avoided costs are simpler to estimate because settled locational energy prices and capacity market or resource adequacy prices can serve as a proxy. In addition, where regulatory frameworks permit, DERs may participate directly in wholesale markets through aggregations established by FERC Order 2222 or through utility programs with pass-through compensation mechanisms. These wholesale revenue streams are available to DERs in vertically integrated RTO member states as well as restructured ones; the key difference is whether the utility passes market value through its own tariff or the DER owner accesses it through an aggregator or retail supplier.

Table 5 combines the two parameters and identifies, for each of the four resulting market structures, where DER value originates, how it reaches the DER owner, and representative jurisdictions. Notably, a vertically integrated utility inside MISO, SPP, or PJM occupies a different quadrant from a vertically integrated utility outside any organized wholesale market, even though both are "vertically integrated," and the framework's compensation design should reflect that difference.

Table 5: Source of DER Value by Market Structure (Retail x RTO/ISO Membership)

	Outside an RTO/ISO (No Organized Wholesale Market)	Inside an RTO/ISO (Organized Wholesale Market)
Vertically Integrated Retail (Utility procures supply)	Value Source: Utility avoided costs. Energy and capacity value derive from the utility's own avoided generation, T&D, and fuel costs, established through integrated resource planning (IRP) and administratively set avoided-cost studies. DER Path to Value: Utility tariff or contract (Pathways 1, 2, and 3); utility is sole planner, procurer, and off-taker. Examples: Non-RTO utilities in the Southeast and Mountain West (e.g., Xcel Colorado).	Value Source: Hybrid. Capacity and T&D value derive from utility avoided costs (IRP); energy value is benchmarked to RTO locational prices, and DER capacity may be credited against the utility's RTO resource adequacy obligation. DER Path to Value: Utility tariff or contract; utility may register DER capacity with the RTO and pass through market value. Examples: Vertically integrated utilities in MISO, SPP, or PJM (e.g., MidAmerican Energy).
Restructured Retail (Third-party suppliers procure supply)	Value Source: Distribution utility avoided T&D costs only; supply value flows through competitive retail suppliers rather than the distribution utility. DER Path to Value: Distribution tariff or NWA contract for locational value; supply value via retailer contract.	Value Source: Market prices. Energy value from RTO locational energy prices; capacity value from the RTO capacity market or state resource adequacy requirement; T&D value from distribution utility avoided costs. DER Path to Value: Direct or aggregated wholesale participation (FERC Order 2222), utility pass-

	Outside an RTO/ISO (No Organized Wholesale Market)	Inside an RTO/ISO (Organized Wholesale Market)
	Examples: Rare in practice—nearly all restructured retail states sit inside an RTO/ISO.	through tariffs (e.g., NY VDER), or distribution NWA solicitations. Examples: New York (NYISO), Massachusetts and Connecticut (ISO-NE), Illinois and Maryland (PJM).

VII. Balancing Utility and Third-Party Roles

Unlocking DER value requires procurement pathways that are transparent, accessible, and structured to ensure fair compensation and competition on terms comparable to traditional utility resources. In the DCP Framework, this depends on clearly defined roles that assign responsibilities for delivering an affordable and reliable energy system.

A utility's primary objective in the DCP Framework is to operate the grid in a safe, cost-effective, and reliable manner. Utilities need confidence that procured DERs will perform when and where needed, which argues for clear performance obligations and dispatch protocols rather than utility control of the asset. For the pathways to work, the regulatory framework must position the utility as a neutral facilitator of DER procurement and integration—which, given the incentives described earlier, is a matter of ratemaking design (Principle 9) rather than utility good faith.

From a customer perspective, DERs can have a measurable impact on electricity bills, onsite consumption, and experienced reliability. Third-party DER owners and operators are similarly motivated by the potential to provide these benefits to customers and the grid at large. Within the DCP Framework, customers and third parties are empowered to drive investment and innovation in DERs while actively participating in markets to capture this value. Third parties can also deliver DER aggregation services to utilities and customers alike, maximizing value that individual DERs could not achieve on their own.

Policy and Design Considerations

Effectively implementing the DCP Framework requires deliberate, principle-driven regulatory structures. The pathways described in the preceding sections define *what* a methodical DER procurement landscape looks like; this section addresses *how* a commission can put it in place. The 10 principles below follow the framework's overarching approach: planning discipline first, then pathway selection, ownership boundaries, compensation design, and finally the accountability structures that sustain the framework over time. Each principle is paired with concrete regulatory instruments that can enable implementation. Those instruments are consolidated in Appendix 1 at the end of this section.

Broadly, the policy tools cluster into four regulatory levers: planning requirements, tariff and procurement approval conditions (including coordination with wholesale participation rules under Order 2222), ratemaking treatment, and verification and reporting rules. Most jurisdictions already possess each of these levers. The framework, as suggested, appears, in many states, to fall within commissions' existing planning, tariff, and ratemaking authority—a point each jurisdiction will need to confirm—and depends less on new authority than on the deliberate, coordinated use of powers commissions already hold.

Principle 1: Procurement Follows Needs, Not the Reverse.

DER procurement should be anchored in needs identified through planning, but the relevant planning process varies by pathway. Broad, tariff-based deployment under Pathway 1 is appropriately informed by system-level energy, capacity, and resource adequacy needs identified in integrated resource planning and bulk system assessments. Targeted procurements under Pathway 3 require more granular, locational grid-need findings that emerge from bottom-up distribution planning.

Critically, the maturity of a jurisdiction's power system planning should not become a barrier to cost-effective DER deployment. Where energy, capacity, or resource adequacy needs are already known at the system level, tariff-based pathways can and should proceed; more granular distribution planning is a prerequisite for targeted, location-specific procurement, not for the framework as a whole.

Policy Tools:

- Integrated resource planning and resource adequacy assessments as the need basis for tariff-based pathways
- Distribution system planning filing requirements with mandated hosting capacity and grid needs analyses for targeted procurements
- Commission rules requiring a documented need finding as a precondition for program or solicitation approval
- Standardized grid needs identification templates in planning dockets

Principle 2: Use the Least Restrictive Mechanism That Can Meet the Need.

The pathways are intentionally preference-ordered. Open, standardized tariffs should be the default option for delivering required services; escalation to competitively informed tariffs or targeted solicitations is warranted only when the locational or timing needs are specific enough to justify departing from that default. In addition, regulators should require utilities to substantiate why a need cannot be met through an earlier pathway before authorizing a later one.

Policy Tools:

- Pathway hierarchy reflected in commission policy or rule
- An “escalation showing” requirement that obligates the utility to demonstrate why an earlier pathway cannot serve the need before a later pathway is authorized
- A rebuttable presumption in favor of tariff-based mechanisms

Principle 3: Procure Services, Not Technologies.

Define grid needs in terms of the required service, with eligibility open to any resource or configuration that can verifiably deliver it. Technology-neutral specifications protect against both utility preference for familiar assets and industry preference for favored ones.

Policy Tools:

- Technology-neutral eligibility language in tariff and RFP approval orders
- Service-defined, rather than asset-defined, product specifications
- Commission authority to reject solicitations drafted around a predetermined technology or vendor

Principle 4: Third-Party and Customer Ownership as Default; Utility Ownership Is an Exception.

Utility ownership should be available only in defined situations, like where there is demonstrably thin market interest or a need for deep operational integration with existing utility infrastructure. Such circumstances should carry guardrails: a demonstrated failure or infeasibility of competitive supply, insulation from rate base incentive distortions where possible, and sunset or re-evaluation terms. The burden of demonstrating that an exception applies rests with the utility.

Policy Tools:

- Ownership guardrail conditions in certificate or program approval orders, including burden-of-proof assignment, market-failure demonstration requirements, and sunset or re-evaluation clauses
- Code-of-conduct and affiliate rules
- Rate base exclusion or modified return treatment for assets that fail the bounding test

Principle 5: Anchor Compensation in the Value Delivered, Built Up by Service and Sharpened by Location and Performance.

Administratively established rates should be built up service by service—capacity, energy, avoided distribution and transmission, and other quantified value streams—using a commission-approved avoided cost methodology for each component; this is the value-stack approach New York and other states have used. Competitive price discovery is a complement for services where there is limited ability to estimate value. Compensation should be reserved for services that exceed the baseline capabilities already required as a condition of interconnection (for example, the ride-through and autonomous volt-var functions specified in IEEE 1547-2018), so that mandatory interconnection behavior is not double-counted as a compensable grid service. Interconnection rules and compensation design should be developed together, so that flexible interconnection options and compensable services are consistent.

Policy Tools:

- Commission-approved avoided cost methodologies updated on a set cadence
- Locational value adders in tariff design
- Interconnection-baseline carve-out language distinguishing compensable services from interconnection agreement obligations

Principle 6: Level the Evaluation Playing Field Before Capital Is Committed.

DER alternatives should be evaluated against traditional wires solutions on a consistent cost-effectiveness basis—the same discount rates, the same risk treatment, the same treatment of deferral value—and that comparison must occur before the utility's capital plan is approved, not after the infrastructure decision is functionally made.

Policy Tools:

- Non-wires alternative screening requirements in capital budget review
- A standardized benefit-cost analysis framework adopted by order, with consistent discount rates and deferral value treatment
- Where jurisdictions choose to adopt it, suspension of capital project approval pending completion of an alternatives analysis

Principle 7: Tie Compensation to Verified Performance.

Every pathway needs measurement, verification (M&V), and consequences: telemetry or M&V appropriate to the resource type, performance-based payment structures, and remedies for non-performance. Verified performance is what makes DER procurement credible as an infrastructure alternative.

Policy Tools:

- M&V protocols adopted as tariff attachments
- Performance-based payment structures with liquidated damages or capacity de-rating for non-performance
- Telemetry and data-access requirements in interconnection and program agreements

Principle 8: Fit the Framework to Market Structure.

Applications differ between vertically integrated and restructured jurisdictions: who conducts the solicitation, how avoided costs are estimated, and how distribution-level procurement coordinates with wholesale market participation under FERC Order 2222. The framework's structure is jurisdiction-agnostic, but implementation should be tailored to each jurisdiction's needs.

Policy Tools:

- Implementation orders specific to each jurisdiction
- Coordination protocols for regional market participation and alignment with FERC Order 2222
- Rules for deriving avoided costs referencing market prices when available and administrative estimates when unavailable

Principle 9: Address the Utility's Incentive Misalignment.

The utility's preference for capital expenditure is not mitigated solely through the existence of a framework. Regulators should pair the framework with incentive mechanisms, shared savings, performance incentives tied to cost-effective DER procurement, or ratemaking treatment that mitigates a utility's financial preference for wires versus non-wires solutions.

Policy Tools:

- Shared-savings mechanisms for cost-effective DER procurement
- Performance incentive metrics tied to non-wires deployment
- Total expenditure ("totex") or capitalization-neutral ratemaking pilots

Principle 10: Build Standing Programs, Not One-Off Efforts.

Durable, repeatable mechanisms with scheduled recalibration to include rate updates, capacity block reviews, and periodic program evaluation give developers the investment certainty that episodic RFPs cannot and give regulators a lever for course correction without starting over.

Policy Tools:

- Program tariffs with scheduled rate recalibration and capacity block structures
- Multi-year procurement authorizations with annual true-ups
- Mandatory periodic program evaluation filings with defined course-correction triggers

Appendix 1: Implementation Considerations

#	Principle	Policy Tool
1	Procurement follows need, not the reverse.	IRP and resource adequacy assessments as a need basis for tariff-based pathways; distribution system planning filing requirements with hosting capacity and grid needs analyses for targeted procurements; pathway-scaled need finding as a precondition for approval; standardized grid needs identification templates
2	Use the least restrictive mechanism that can meet the need.	Pathway hierarchy codified in policy or rule; “escalation showing” requirement; rebuttable presumption favoring tariff-based mechanisms
3	Procure services, not technologies.	Technology-neutral eligibility language; service-defined product specifications; commission rejection authority over technology-predetermined solicitations
4	Third-party and customer ownership as default; utility ownership is an exception.	Ownership guardrail conditions (burden of proof, market-failure demonstration, sunset/re-evaluation); code-of-conduct and affiliate rules; rate base exclusion or modified return treatment
5	Anchor compensation in the value delivered, built up by service and sharpened by location and performance.	Approved avoided cost methodologies on set update cadence; locational value adders; interconnection-baseline carve-out distinguishing compensable services from interconnection agreement obligations
6	Level the evaluation playing field before capital is committed.	NWA screening in capital budget review; standardized benefit-cost framework adopted by order; suspension of capital approval pending alternatives analysis (where adopted)
7	Tie compensation to verified performance.	M&V protocols as tariff attachments; performance-based payments with liquidated damages or derating; telemetry and data-access requirements
8	Fit the framework to market structure.	Jurisdiction-specific implementation orders; RTO/ISO coordination protocols (Order 2222 alignment); market-referenced avoided cost derivation rules
9	Address the utility’s incentive misalignment.	Shared-savings mechanisms; performance incentive metrics tied to non-wires deployment; totex/capitalization-neutral ratemaking pilots; earnings-basis adjustments
10	Build standing programs, not one-off efforts.	Program tariffs with scheduled recalibration and capacity blocks; multi-year procurement authorizations with annual true-ups; mandatory periodic evaluation filings with course-correction triggers

Appendix 2: Use-Case Mapping Matrix

Grid Need/Use Case	DER Configurations	BTM/FTM	Procurement Pathway and Mechanism	Rationale
System-wide / diffuse load growth	Solar, storage, solar + storage, demand response (DR), VPPs	Both	Pathway 1: Programmatic tariff	Broad-based capacity and energy; not site-specific
Substation-specific capacity constraint	FTM storage, FTM solar + storage, targeted VPPs, DR	Both	Pathways 2 or 3: RFP-informed tariff or RFP	Locational; requires planning-driven procurement
Feeder-level thermal overload	FTM storage, local BTM aggregation, targeted DR	Both	Pathways 2 or 3: RFP-informed tariff or RFP	Highly locational; feeder coordination needed
Steady-state voltage support	Smart inverters (solar + storage), FTM storage w/ reactive	FTM	Pathway 2: RFP-informed tariff	Specific inverter capabilities; locational
Reactive power at specific locations	FTM storage or static synchronous compensator (STATCOM) - equivalent DER	FTM	Pathway 3: RFP	Site-specific; operational integration
Worst-performing circuit remediation	FTM storage, local microgrids, DER backup	FTM	Pathway 3: RFP	Site-specific; protection coordination
Resource adequacy contribution	Distributed solar + storage, VPPs	Both	Pathway 1: Tariff (resource adequacy adder)	Broad-based resource availability
Critical facility backup	Solar + storage microgrids, standalone storage	Both	Pathway 3: RFP	Bespoke design; facility-specific
Community resilience hubs	Solar + storage microgrids, multi-customer configs.	FTM	Pathway 3: RFP	Community-specific design
Substation upgrade deferral	FTM storage, FTM solar + storage, DR/VPP portfolio	Both	Pathways 2 or 3: RFP-informed tariff or RFP	Tied to specific capital project

Grid Need/Use Case	DER Configurations	BTM/FTM	Procurement Pathway and Mechanism	Rationale
Feeder reconductoring deferral	FTM storage, targeted BTM aggregation	Both	Pathway 2: RFP-informed tariff	Locational; tariff w/ locational adder
New substation avoidance	Portfolio of DER (FTM + BTM aggregation)	Both	Pathway 3: RFP	Large-scale; coordinated portfolio
System-wide peak reduction	DR, BTM storage, VPPs, time-of-use (TOU)-responsive load	BTM	Pathway 1: Tariff (time-differentiated)	Broad-based demand flexibility
Local area peak management	Targeted DR, FTM storage, localized VPPs	Both	Pathway 2: RFP-informed tariff	Locational within open tariff
Reverse power flow management	Storage (absorbing excess generation)	FTM	Pathway 2: RFP-informed tariff	Tied to high-DER-penetration feeders
Hosting capacity expansion	Storage paired with existing solar, smart inverters	Both	Pathway 2: RFP-informed tariff	Enables additional Pathway 1 deployment
Asset replacement scope reduction	FTM storage, FTM solar+storage	FTM	Pathway 3: RFP	Tied to specific capital project

Appendix 3: Glossary of Acronyms

Acronym	Term
BESS	Battery energy storage system
BTM	Behind-the-meter
DCP	Distributed Capacity Procurement Framework
DER	Distributed energy resource
DMS	Distribution management system
DR	Demand response
ESS	Energy storage system
FERC	Federal Energy Regulatory Commission
FLISR	Fault location, isolation, and service restoration
FTM	Front-of-the-meter
IRP	Integrated resource plan
ISO	Independent system operator
ISO-NE	Independent System Operator New England
M&V	Measurement and verification
MISO	Midcontinent Independent System Operator
MW	Megawatt
NYISO	New York Independent System Operator
NWA	Non-wires alternative
PJM	PJM Interconnection
RFP	Request for proposals
RTO	Regional transmission organization
SCADA	Supervisory control and data acquisition
SPP	Southwest Power Pool
STATCOM	Static synchronous compensator
T&D	Transmission and distribution
TOU	Time-of-use
VPP	Virtual power plant