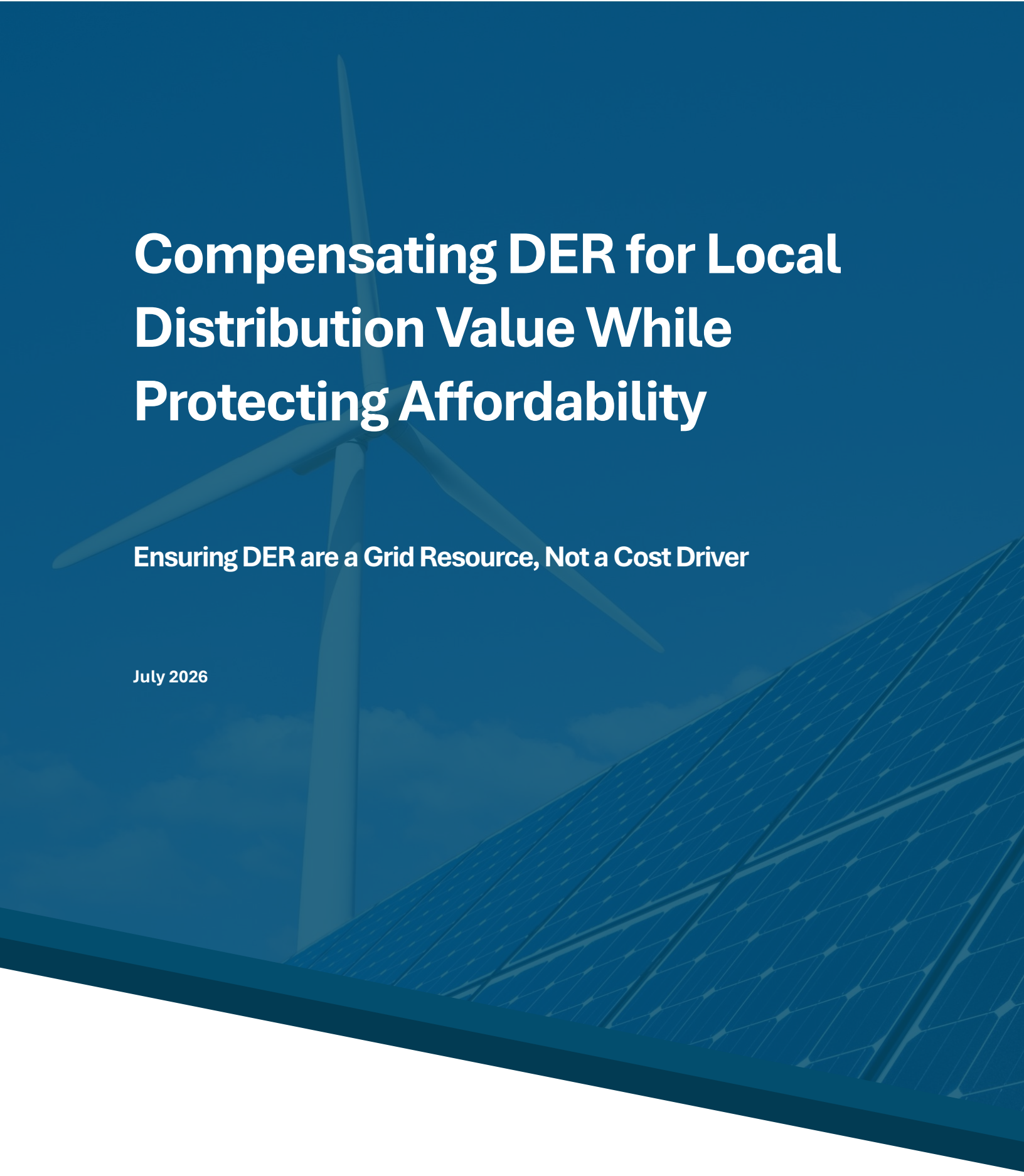

Compensating DER for Local Distribution Value While Protecting Affordability

Ensuring DER are a Grid Resource, Not a Cost Driver

July 2026

Energy+Environmental Economics

Authors and Acknowledgments

Energy and Environmental Economics, Inc. (E3) is a leading economic consultancy focused on the clean energy transition. For over 30 years, E3's analysis has been used by utilities, regulators, developers, and advocates who are writing the script for the clean energy transition in leading-edge jurisdictions such as California, New York, Hawaii, and elsewhere. E3 has offices in San Francisco, Boston, New York, Denver, Chicago, and Calgary.

Authors: Eric Cutter, Jeremy Laundergan, Mike Sontag, Margo Bonner

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Executive Summary

Energy affordability is a paramount concern for regulators and customers, as affordable electricity is crucial for decarbonization, economic growth, and energy equity. Distribution is the largest source of utility capital spending; inflation-adjusted distribution and transmission expenditures rose from 2019 through 2024 as utilities replaced aging infrastructure and hardened grids for resiliency. Many utilities are planning significantly higher distribution investment through 2030, even as rate-increase requests and approvals reach multi-decadal highs.[1] Policymakers are justifiably asking for greater transparency into and management of distribution costs, through integrated distribution system planning, the inclusion of distributed energy resources (DER) in distribution planning, flexible interconnections, and, the subject of this paper, compensation for the distribution deferral value that DER can provide.

That scrutiny has also produced a temptation to legislate around the utility and its regulators. Frustration with rising bills, the opacity of distribution planning, and a business model that rewards capital investment has led some policymakers and advocates to propose highly prescriptive legislation. This approach is premised on utility resistance as the principal barrier to DER deployment. But utilities are more constrained by the capital and workforce they can deploy each year, and they have a strong incentive to direct that limited capacity toward the investments that deliver the most incremental value, whether reliability, resiliency, or new revenue. Legislation setting compensation for DER can appear to be a shortcut, but it locks in assumptions that will not hold as the grid evolves and risks deepening the affordability problem it is meant to relieve. Working through the regulator to align DER compensation with the distribution value these resources actually deliver is the more durable path, keeping utilities, state agencies, and third parties pointed toward a common outcome rather than working around one another.

The distribution grid is being asked to serve a rapidly growing load, driven by the electrification of vehicles and buildings and by new large customers. DERs include customer-owned generation such as solar PV, batteries, demand response, and flexible loads. The non-wires alternative and non-wires solution (NWA/NWS) and virtual power plant (VPP) programs that orchestrate them can help by providing grid services when and where the grid is constrained. States and utilities are moving quickly to implement a growing array of local value of DER (LVDER) programs that pay for these local distribution benefits; however, realizing that value in reduced infrastructure cost depends on program design that reflects where, when, and how reliably a DER serves a local grid need. Poorly designed compensation can do the opposite, as illustrated by net energy metering for PV, which has contributed to very significant rate increases in some states.[2] Energy and Environmental

Economics (E3) developed the Local Net Benefits Analysis framework used to quantify distribution deferral value for California's investor-owned utilities and has applied analogous methods in New York, Illinois, and Massachusetts. Drawing on those proceedings, this paper establishes the analytical basis for local distribution value, examines the program design choices that determine whether it is captured, and proposes a compensation framework that supports a robust and cost-effective DER market.

This paper values distribution deferral, not resiliency, community, or other non-energy benefits, which may be real but are hard to monetize and are not reflected in rates or the utility's avoided costs. Compensating these additional benefits through electricity rates would add to, rather than mitigate, affordability challenges.

The opportunity for local value of DER is narrower than top-down studies suggest. Potential assessments conducted at the statewide level point to hundreds of millions or billions of dollars per year in avoidable distribution costs, but these screening-level figures are directional upper bounds; achievable savings are smaller and depend on location- and time-specific dispatch. PG&E's Electrification Impact Study illustrates the gap: orchestrated flexible load can cut cumulative distribution investment through 2040 by roughly $1.8 billion, about 7% of distribution costs, but only when dispatched to local conditions. That saving falls to about $0.15 billion when the same resources are dispatched to bulk-system price signals. The value is also spatially concentrated, since utilities' distribution grid needs assessments identify needs at only about 10% of feeders and substations, of which only a fraction can be deferred by DER.[3] Programs designed around those conditions can capture real savings and scale with adoption without producing the cost shifts that threaten energy affordability.

Distribution capacity costs are driven by the coincident peak load of thousands of customers at the primary system and by the non-coincident maximum demand of a small number of customers on the secondary system. Distribution capacity costs are avoidable only when a resource reduces the driver of the grid need at the specific location and hours that trigger an upgrade to meet the grid need. Compensation benchmarked to the average marginal cost of serving load rather than the avoided cost of grid services provided by DER systematically overpays relative to the distribution value that can be realized in practice.

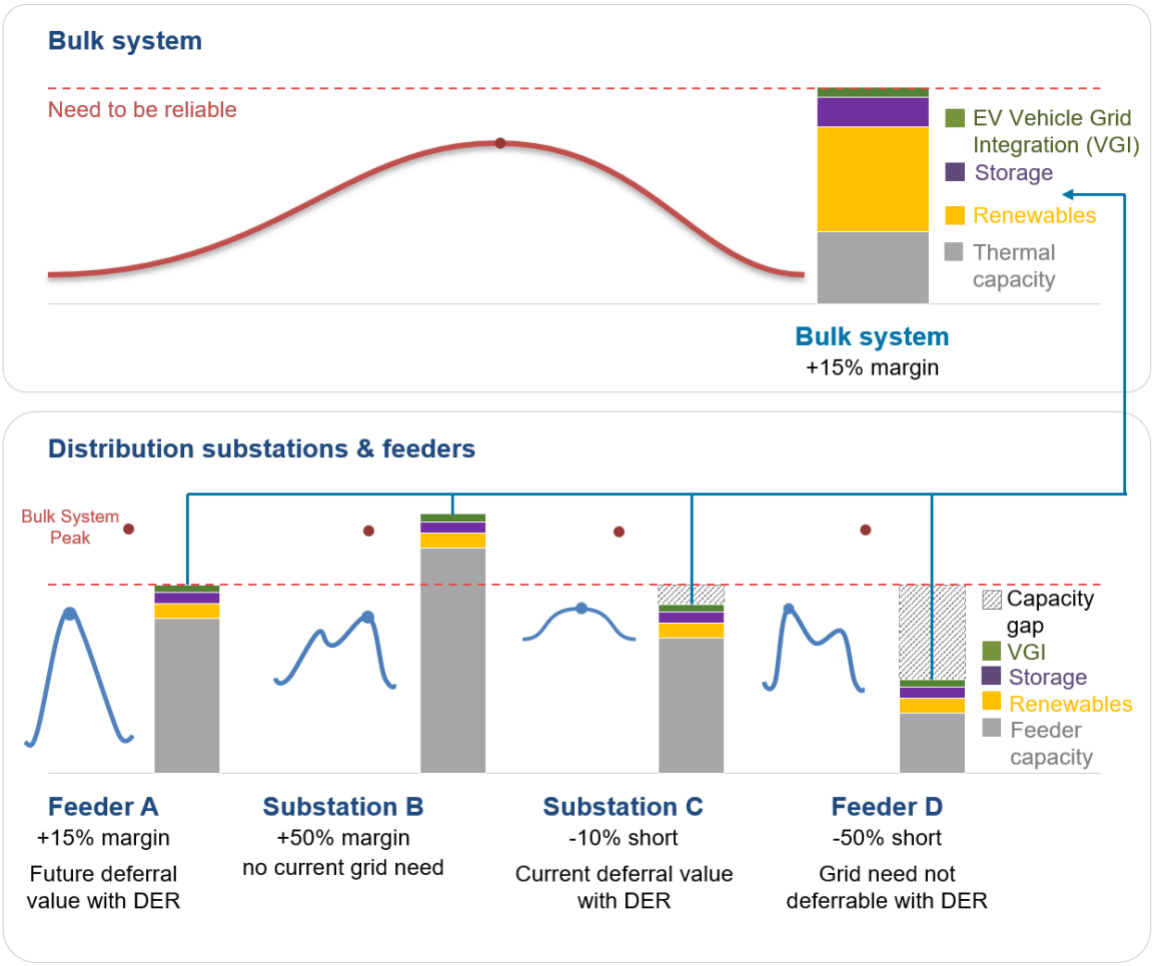
Table 1. Concepts for Average, Marginal, and Avoided Distribution Cost

Cost Category	Non-Marginal, Non-Load Related Costs		Marginal Costs			
	Embedded/ Sunk	Age Related Replacement	Primary Capacity	Secondary Capacity	New Business	Customer Access
	Existing Substation	Replace Aging Infrastructure	Add New Substation Transformer	Upsize Final Line Transformer	Line Extension to New Customer	Service Drop to Customer
Average	✓	✓	✓	✓	✓	✓
Marginal			✓	✓	✓	✓
Avoided			✓	✓ *		

** Avoiding secondary capacity costs relies on reducing non-coincident peak and connected load among a small number of customers, which is more challenging than reducing coincident peak load on the primary distribution system.*

Distribution value is harder to capture than bulk-system capacity value. In many regions, resource adequacy or capacity requirements are set against a single system-wide peak, so any reliable load reduction during that peak period has value regardless of where it occurs. Distribution capacity is more challenging in every dimension: the need sits at selected feeders, peaks in hours that differ across the system, calls for only the discrete reduction that defers a planned upgrade, and lasts only until that upgrade is built. Serving the bulk peak resembles an ongoing highway repaving program, while distribution needs are more like potholes that open at specific spots, get filled, and form again (**Figure 1**).

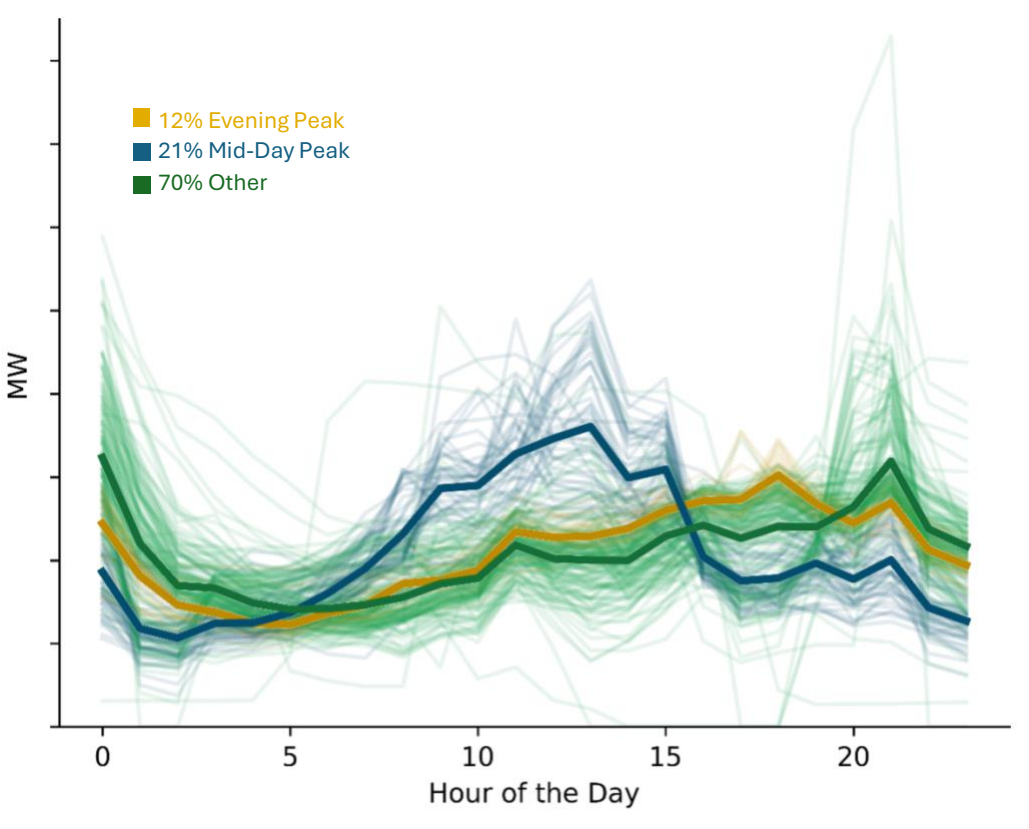
Figure 1. Conceptual Differences in Bulk and Distribution Capacity Planning



DER are customer-owned assets, operated for their comfort and cost savings rather than to serve the grid. A DER program therefore depends on the voluntary actions of those asset owners, often requiring a deviation from the routine customer use and providing less than the full DER nameplate capacity. That dependable contribution, the distribution analog to effective load carrying capability (ELCC), turns on three attributes, each measured against local conditions:

- **Coincidence:** whether the resource's output aligns with the hours the local feeder peaks, which often diverge from the bulk-system peak (**Figure 2**).
- **Availability:** how much of the enrolled resource shows up when called, given opt-outs, dispatch fatigue, and the customer's own use.
- **Duration**: whether it can sustain its output for the entire time it is needed, from a multi-hour feeder peak to a multi-day heat wave.

Figure 2. Illustrative Diversity of Forecasted Feeder Load Shapes for a Municipal Utility in the Western U.S.



Modeling DER by these attributes, not by installed capacity, is what lets a distribution planner count on them to defer a distribution upgrade, and what a sound compensation program must reward.

The compensation rules written today will govern a growing DER fleet, so the cost of getting them wrong grows with the market they create. Net energy metering is the cautionary precedent: a credit set generously to launch the rooftop solar market became embedded in customer expectations, installer models, and project financing, and the resulting cost shift proved politically difficult to unwind. Distributed storage is now scaling even faster than early rooftop solar, making this the moment to set verified, locational, performance-based compensation before business models harden around overly generous and imprecise payments.

Most current programs that compensate for distribution value have not yet adopted the design features that keep compensation tied to realized value. Many share one or more of five structural flaws that create systematic overcompensation risk:

- **Marginal rather than avoided costs** as a basis for compensation
- **System-wide rather than targeted compensation** focused on feeders with identified needs
- **Bulk-system-based dispatch windows** rather than dispatch based on local feeder conditions
- **Enrolled rather than effective capacity-based compensation**
- **Long commitment terms** that lock these structures in, even as grid conditions change

Because of these flaws, programs often steer payments to resources that may deliver no distribution value, leading to entrenched overpayment as the DER fleet grows. This imposes increased costs on all ratepayers without a commensurate reduction in utility investment. Many behind-the-meter resources also already earn compensation through their retail rate, so an LVDER payment should credit only the dispatch a resource delivers beyond what net-metering or time-of-use rates already elicit, ensuring ratepayers do not pay twice for the same response. Compensation should likewise account for the wholesale energy and capacity revenue a resource forgoes by dispatching to local needs; where the avoided distribution cost cannot cover that opportunity cost, the resource is better left serving the bulk system.

The framework proposed in Section 4 corrects these gaps by holding LVDER compensation to three principles:

- **Compensate below the avoided cost.** Anchor payment to a verified distribution avoided cost, not a theoretical marginal cost, and credit only the value a resource delivers beyond what its retail rate already pays.
    - **Two Tiers: a System-Wide Baseline and a Targeted Locational Payment**: a modest system-wide payment to every DER for the diffuse value of broad load reduction, and a targeted locational payment that applies only where a resource can defer an identified distribution investment.
    - **Credit Only Value Beyond the Retail Rate:** Credit only the value a resource delivers beyond what its retail rate already pays for, since retail bill savings and existing tariff credits already compensate DER for part of the value they provide.
    - **A Revenue Term Long Enough to Finance, Short Enough to Recalibrate:** Set the revenue term long enough to finance investment but short enough to recalibrate as grid conditions change.
- **Pay for measured performance, not enrollment.** Tie compensation to the grid impact that a resource verifiably delivers rather than to the capacity it enrolls.

- **Eligibility and Caps**: Limit eligibility for the locational payment to feeders with an identified, deferrable need, and cap enrollment at the quantity that relieves it.
- **Dispatch Windows Set to Distribution Peaks:** rather than bulk-system periods, so resources reduce load in the hours that actually defer feeder investment.
- **Payment for Effective Capacity Delivered During Critical Hours**: Credit the effective capacity a resource delivers during those critical hours, trued up against measured performance, rather than its nameplate or enrolled capacity.

+ **Streamline and consolidate programs.** Incorporate locational compensation into a consolidated set of existing programs rather than standing up separate LVDER programs.

    - **Interoperable, open standards and robust APIs** for enrollment, dispatch, and measurement enable a utility to qualify many aggregators, devices, and customers, lowering the fixed and administrative costs and increasing the net benefit for customers and ratepayers.
    - **Enable DER to stack and co-optimize grid services** where feasible, and direct each resource to its highest-value use where stacking is not feasible.
    - **Balance enrollment and performance risk** so third-party business models remain viable without exposing ratepayers to overpayment.

This approach does not require new technology or a slowdown in DER deployment; rather, it proposes that compensation reflect the distribution value these resources actually deliver. This lets programs scale with a growing DER fleet while maintaining a sustainable revenue stream and protecting affordability for all ratepayers. Get program design and compensation right at the start, and the same load growth that now pressures rates will become a resource that helps lower them, with DER earning durable revenue, utilities deferring real investment, and every ratepayer sharing in the savings.

The Opportunity for LVDER Today

Introduction: Why LVDER, Why Now

The conventional path to meeting load growth from electrification and new large customers is not keeping up with demand, as interconnection backlogs, permitting timelines, and supply constraints on long-lead time equipment slow traditional utility infrastructure buildout. [4] Utilities, regulators, and legislators are responding with a growing array of programs that enlist distributed energy resources (DER) to meet grid needs: virtual power plant programs, non-wires alternative and non-wires solution solicitations, storage incentive tariffs, and demand response and flexible load programs that offer incentives and compensation for distribution deferral value.

Utility planning seeks to balance supply and demand within the physical limits of the infrastructure at both the bulk and distribution system levels, but how DER can serve grid needs at each level is quite different. At the bulk system level, grid needs are quantified primarily through the wholesale energy and capacity markets, where a transmission or generation constraint raises the price at the affected node or capacity zone. Wholesale markets include demand response under FERC Orders 719 and 745, energy storage under Order 841, and DER aggregations under Order 2222. No equivalent market mechanism exists in the distribution system, where the utility, acting as a monopoly distribution operator, plans and monitors it. Where viable DER grid services are available, the utility incorporates them in planning to relieve an emerging need: reducing load or adding local supply as infrastructure approaches its thermal or capacity limit, and absorbing surplus generation into storage or flexible load where local distributed generation approaches hosting capacity limits. These distribution needs differ in time and place from the bulk system as discussed further in Section 3.

Compensation for distribution grid services is nascent, and early programs share common design gaps: payments rest on a theoretical avoided cost estimate without verifying that any specific investment is deferred, and incentives apply across a service territory without targeting the feeders where needs actually exist. Retail rate design shapes much of the underlying behavior and is part of the same story, since the rate a customer already faces determines how much additional response an LVDER payment must purchase. Aligning compensation with realized value now, while program structures are still forming and expectations have not hardened, is substantially easier than reforming entrenched programs once business models have formed around them.

This paper establishes the analytical basis for local distribution value, showing how investment is triggered at specific feeders and substations, why deferrable value is

concentrated at a small share of the grid, how bulk-system dispatch signals diverge from distribution needs, and why nameplate capacity overstates the effective contribution of energy-limited distributed resources. Building on that basis, it examines the structural design choices that create systematic risk of overcompensation, alongside approaches that mitigate it, and recommends a two-tier compensation framework with eligibility conditions and performance requirements that keep payments tied to realized value. This sustainable pathway supports affordability for all ratepayers.

This paper covers distribution deferral value, not resiliency, community, or other non-energy benefits, which may be real but are difficult to monetize and are reflected neither in rates nor in the utility's avoided costs. Compensating these additional benefits through electricity rates would add to, rather than mitigate, affordability challenges.

Acting Before Overcompensation Becomes Entrenched

Overcompensation arises in two distinct ways, and a durable framework must guard against both. The first is a payment level set above the value the grid actually receives, whether benchmarked to a theoretical rather than a verified avoided cost or built by stacking values that cannot all be earned at once. Such a payment shifts costs to non-participating ratepayers, which may be immaterial at low adoption but becomes more significant as the program scales. The second is a static program structure calibrated to a small resource base that keeps paying for a grid service the system no longer needs as that base grows and the underlying load shape shifts. Section 4 examines the specific design choices behind each and the approaches that address them; the risk itself is not hypothetical, as the compensation history of customer DER shows.

Net energy metering is the clearest precedent, and although it is a bulk-oriented DER program with no locational value component, its trajectory shows how quickly a launch-phase incentive hardens. California's first NEM tariff, enacted in 1996, compensated rooftop solar at the full retail rate, subject to a limited statutory cap.[5] Rather than treating the cap as a trigger to align compensation with avoided cost as the market grew, the legislature raised it in 2002, 2006, and 2010, and the retail-rate credit became embedded in customer expectations, installer sales models, and project financing.[6] The pattern spread nationally, and as of early 2023, 36 states and the District of Columbia still operated retail-rate net metering while 32 states were actively considering changes.[7] Nevada, Maine, and Florida each attempted reforms, only to roll them back after organized opposition from customers and installers whose business models had been built around the prior structure.[8] Because NEM compensated exports without regard to location, it also left real local distribution costs unaddressed, the gap that the LVDER program design is meant to close. In fact, high local solar PV penetration can create distribution grid constraints that require infrastructure upgrades or DER programs to address.

Distributed storage is following the same trajectory as NEM incentivized rooftop solar, but on a compressed timeline. The U.S. storage market set a record in the first quarter of 2026, installing 3.3 GW and 8.4 GWh, with residential storage reaching a record 1.3 GWh, up 86% year over year.[9] Two policy conditions are accelerating that growth: the Inflation Reduction Act extended the 30% residential clean energy credit to standalone storage in 2023, and although the 2025 reconciliation act ended that customer-owned credit under Section 25D after 2025, third-party and commercial systems remain eligible under the Section 48E investment tax credit.[10] Reforms to solar export compensation have, at the same time, made pairing storage with new rooftop solar the norm, as customers self-consume to minimize exports. Storage is scaling on the strength of these policies and is at risk of following the same NEM trajectory of entrenched compensation and growing cost shifts onto other ratepayers as adoption climbs.

Establishing compensation at verified avoided cost from the start, or committing to a defined transition toward it, keeps the emerging market on a footing that can scale and endure.

Three Principles for LVDER Programs to Realize Benefits for Ratepayers

Programs that hold to three principles keep DER compensation aligned with the local distribution grid service actually delivered as the market scales. Section 4 develops each into an operational framework; the principles are introduced here because they shape how its design choices should be read.

Compensate Below Avoided Cost for Ratepayer Benefit

Anchor to verified, locational avoided cost. LVDER compensation should be anchored in, but set below, verified avoided cost rather than a theoretical marginal cost estimate or an administratively set incentive. This keeps program costs below the avoided utility investment and ensures net savings for all ratepayers.

Two tiers, a system-wide baseline and a targeted locational payment. The framework pays in two tiers: a modest system-wide baseline available to every DER for the diffuse value of broad load reduction, and a targeted locational payment that applies only where a resource can defer an identified investment.

Credit only value beyond the retail rate. Compensation must also be incremental to the retail rate. Many DERs already earn value responding to net metering, net billing, or time-of-use rates, so a resource should not be paid twice for the same response.

A revenue term long enough to finance, short enough to recalibrate. Revenue terms should run long enough to finance the investment but short enough to recalibrate as grid needs change.

Pay for Accurately Measured Performance (Not Enrollment)

Measure what is delivered, not nameplate. Distributed resources are first customer assets, acquired and operated for comfort, convenience, and cost rather than to serve the grid, so what the grid can rely on is set by customer participation and tolerance for dispatch and can be established only by measuring what a resource delivers, not by assuming what its nameplate implies.

Eligibility and caps. Eligibility for the locational payment should be limited to feeders with an identified, deferrable need, with enrollment capped at the quantity that relieves it.

Dispatch windows set to distribution peaks. Dispatch should follow the local distribution peaks and critical hours that drive the grid need rather than bulk-system periods.

Payment for effective capacity delivered during critical hours. Nameplate or enrolled capacity should be discounted to the effective capacity a resource reliably delivers – the distribution-level analog to the ELCC discount used in bulk-system resource adequacy. Because some enrolled DER underperform, decline, or drop out, programs must size enrollment with a buffer above the target and refine that derating as measured performance accumulates.

Streamline and Consolidate Programs

Consolidate overlapping programs. Scaling DER participation without a proportional rise in administrative cost requires consolidating overlapping programs and vendor-specific enrollment paths into a smaller set of well-defined offerings.

Interoperable, open standards and robust APIs let a utility qualify many aggregators and devices against a single specification rather than a bespoke integration for each.

Enable DER to stack and co-optimize grid services. A consolidated portfolio also lets a resource stack and co-optimize grid services, directing each to its highest-value use and, where a distribution deferral and a bulk-system need call for different hours, committing it first to the distribution need it is paid to defer.

Balance enrollment and performance risk. Because these business models depend on revenue that is sufficiently predictable to finance customer acquisition and hardware, program design must balance enrollment and performance risk so that third parties remain viable without exposing ratepayers to overpayment.

How DER Provides Locational Distribution Value

How Much Distribution Value DER Can Provide

Survey-level, top-down studies find substantial potential for distribution value from flexible loads and VPPs. A 2025 Brattle Group study for NYSERDA projected $408 million per year in distribution capacity deferral in New York by 2040.[11] That value is based on 8.5 GW of cost-effective grid flexibility potential, with a projected peak load of 37 GW. A 2025 Evolved Energy Research (EER) study for the Union of Concerned Scientists estimated that vehicle-grid integration across California's light-duty electric vehicle fleet could lower annual energy system costs by $2 to $12 billion in 2045.[12] Avoided distribution costs ranging from $1 to $10 billion per year were a leading source of those presumed savings, based on the assumption that DER can reduce residential distribution peak demand by more than 25% in high-participation scenarios. A 2025 Kevala analysis estimated that California could cut distribution capital costs by $3.2 to $12 billion by 2030.[13]

These top-down figures are directional upper bounds; achievable savings are smaller and depend on location- and time-specific dispatch, as the granular modeling below shows. More granular, bottom-up distribution modeling shows that the opportunity these studies identified is highly sensitive to the location, timing, and achievable DER dispatch potential. PG&E's 2026 High DER Electrification Impact Study focused on primary and secondary distribution investment driven by electrification. PG&E found that orchestrated load flexibility could cut cumulative distribution investment through 2040 by roughly $1.8 billion, which represents about 7% of total distribution costs.[14] The PG&E, Kevala, and EER figures cover different time horizons, geographic footprints, and modeling approaches, so they are not directly comparable. PG&E's more granular LoadSEER and CYME distribution planning models nonetheless produced a materially lower savings estimate than Kevala's and EER's higher-level statewide approaches, consistent with the pattern in which granular, location-specific modeling finds smaller achievable benefits than top-down potential studies. Furthermore, that value materializes only when flexible load resources are dispatched to mitigate local distribution conditions. When the same resources followed bulk-system price signals instead, the savings nearly vanished, falling to $0.15 billion, because dispatch corresponding to peak system demand is not necessarily coincident with the feeder load profile where the DER is interconnected. Similarly, dispatching DER grid services to support local distribution grid needs may correspond with relatively low wholesale market prices.

Differences between Local and Bulk System Value

Distribution planning operates under a different institutional structure than bulk-system capacity markets, and that difference shapes how each side manages the risk of a demand flexibility program underperforming. Wholesale resource adequacy and capacity markets pool many buyers and sellers across a broad footprint, managing system-wide adequacy across thousands of resources and millions of customers, so a shortfall from any one participant is a small fraction of a much larger, liquid market. A distribution utility plans, builds, and maintains the local grid as a regulated monopoly function, sized to meet a specific grid need at a specific feeder, transformer, or circuit segment. That contrast between a regional competitive market and a monopoly planning function calls for a compensation construct designed for the distribution grid rather than one ported over from or bolted onto programs developed for the bulk system.

On the generation capacity side, procurement teams reevaluate load growth and capacity contracts on an ongoing basis and can draw on that liquid market when a program underperforms. A shortfall in expected demand reduction can typically be covered through short-term contracts with other resources bidding into the regional market, and the large pool of participants limits the effect of any single customer or resource opting out for a season. Reserve margins and interconnected systems provide multiple fallback options, and large aggregations smooth individual variability through the law of large numbers.

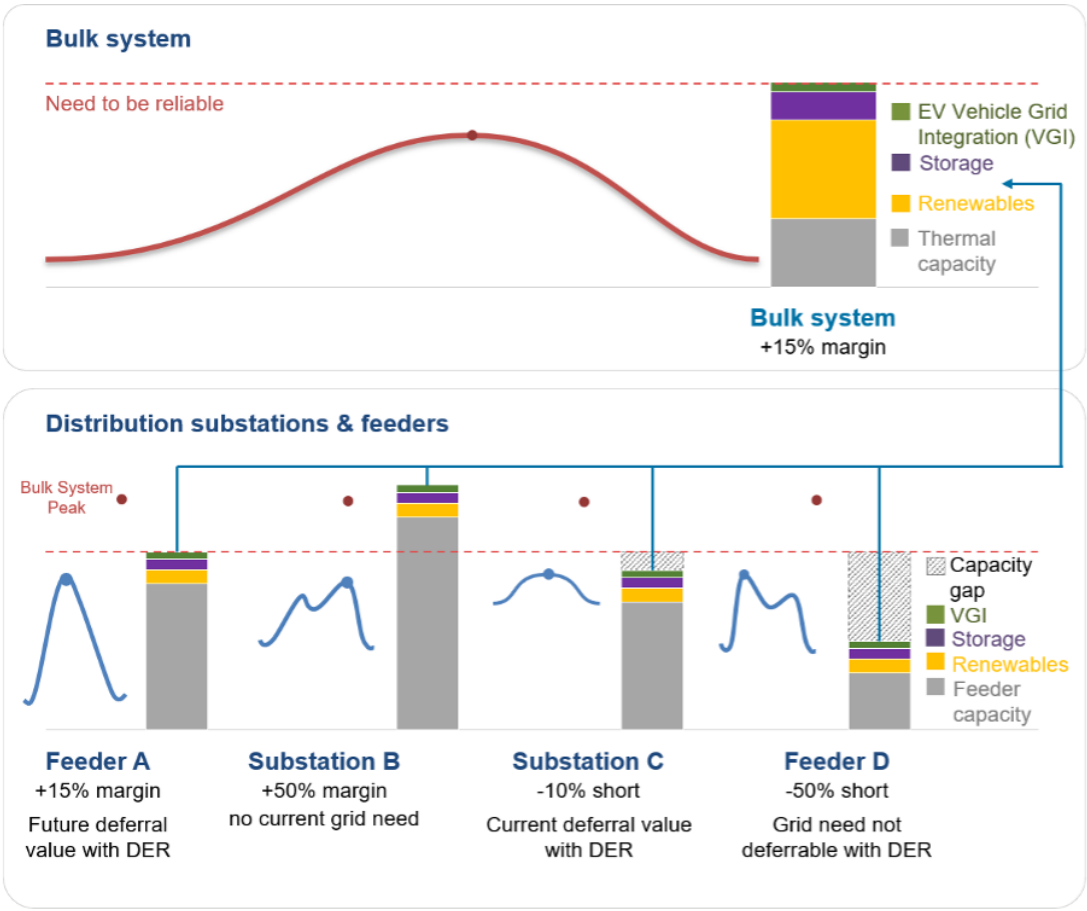
Distribution planning operates over multi-year capital cycles tied to specific feeders and substations, where the statistical averaging of the bulk system is not available. Because these needs are met by discrete, indivisible (or "lumpy") upgrades sized for long-term growth, the investment increment is large relative to the overage that triggers it. A modest, reliable load reduction at the right feeder and hour can potentially defer a large capital cost. Realizing that value depends on where a resource sits, when it dispatches, and how reliably it performs. A DER that responds on a best-efforts basis during reliability events reduces fuel consumption at the bulk system level but cannot substitute for an upgrade when evaluating distribution grid needs during the planning process, which requires firm commitment, accountability, and verified delivery. The scale of the benefit, therefore, depends on designing programs around the intersection of what the grid needs and what DER can reliably deliver.

Customer populations able to serve a single location are small, which limits the smoothing that large aggregations enjoy and leaves the utility more exposed to the behavior of any one participant. When a locational program falls short, the backup options are physical rather than contractual: temporary diesel generation, mobile batteries, or accelerating the planned upgrade, where those options exist at all. Because contingency options at a single location are few, the loss of even one or two participants can be enough to trigger the capital

project that the program was designed to defer. Since infrastructure projects take time to deploy, customers in that area may experience service disruptions in the meantime when the DER cannot provide the needed grid services to mitigate grid needs.

These structural differences produce two planning cultures that approach the same resource with different instincts. Bulk-system resource planners work over horizons of a decade or more, treat uncertainty probabilistically, and model reliability contributions using methods such as loss-of-load probability and effective load carrying capacity, which credit a resource for its statistical contribution to meeting load rather than its nameplate rating. Their planning objectives extend beyond reliability to include clean energy and GHG targets, and their decisions are tested in integrated resource planning proceedings built on transparency and stakeholder engagement. Distribution engineers plan over shorter horizons, size the grid against worst-case conditions, and lean on historical practice and operator experience, because a local failure surfaces immediately as an outage or equipment damage, and safety leaves little tolerance for a resource that may not perform when the feeder is stressed. Distribution planning models and methods remain highly technical and opaque to most regulators and stakeholders. Consequently, DER programs are evaluated in distribution planning using a worst-case, redundancy-oriented framework rather than a probabilistic accreditation that allows the same resource to earn value in the bulk system.

Figure 3. Conceptual Differences in Bulk and Distribution Capacity Planning



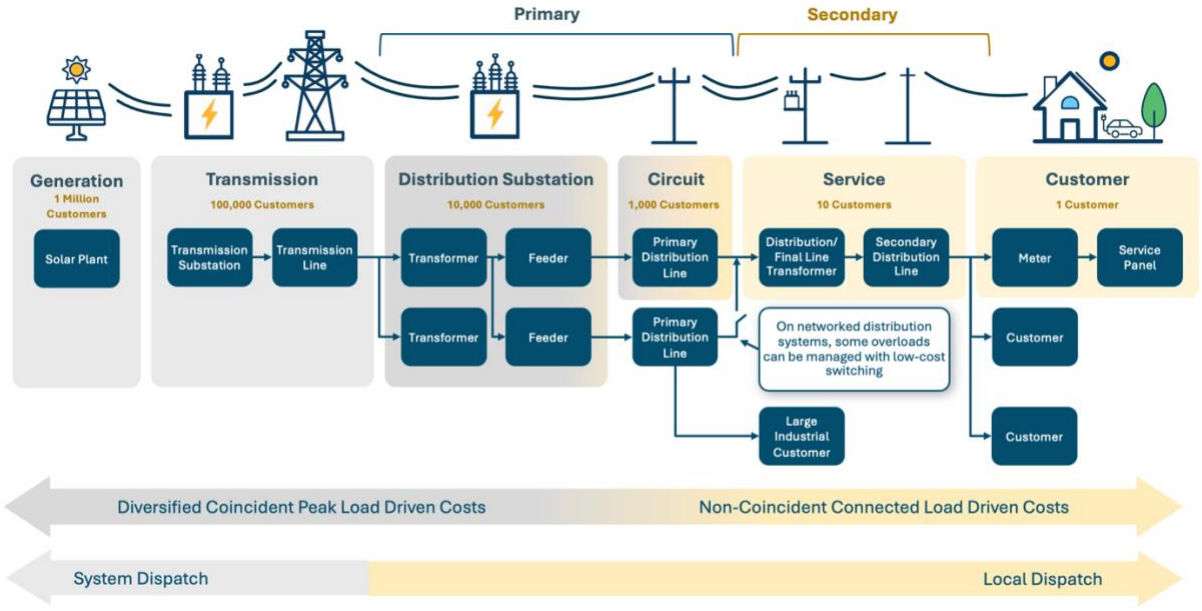
Terminology remains unsettled, but the distinction that matters for compensation is the grid level a resource serves: DER aggregations that serve the bulk system are virtual power plants (VPPs), while non-wires alternatives and non-wires solutions (NWA/NWS) enlist DER to defer a need at a specific substation or feeder. Serving the distribution level also requires the utility to extend visibility and control beyond substation SCADA, through distribution management systems (DMS), advanced distribution management systems (ADMS), and distributed energy resource management systems (DERMS) that identify local needs and dispatch participating DER locally. The time, money, and effort required to establish these operational-enabling DER investments are often underappreciated when utilities are asked to compensate for distribution value or to evaluate and utilize NWA/NWS.

Marginal Distribution Cost Drivers and the Avoided Cost from Load Reduction

Utilities divide the distribution system into three portions that differ in voltage, scale, and the number of customers each one serves (**Figure 4**). The primary system is the upstream, higher-voltage portion, consisting of the distribution substations and the feeders and laterals that branch out from them to carry power across a service area. It is shared among

thousands of customers and sized to their coincident peak load, with significant diversity in the timing of the peak load for each individual customer. The secondary system is the local, lower-voltage portion closer to the customer, consisting of the final line or service transformers and the secondary lines and service drops that connect to individual premises. Because this equipment serves only a small group of customers, it is sized to their local maximum demand, which may or may not coincide with the primary system peak load. Studies measure this local driver in different ways, using an effective demand factor or customer design demand, which includes a lower diversity factor for smaller customer aggregations, reflecting that not all customers will incur their maximum demand at the same time. The final portion is the customer access segment, which includes the service drop and customer meter, sized to the connected load at the customer's service panel.

Figure 4. Conceptual Diagram of Distribution Grid



A marginal cost study quantifies how these costs change as the utility serves more load or more customers, and the resulting cost categories fall into two broad types: capacity costs, which scale with demand, and customer access costs, which scale with the number of customers. Utilities differ in where they draw the boundary between primary and secondary, which types of equipment fall into each cost category, and how they measure the respective cost drivers. Still, the overview that follows applies generally across U.S. utilities.

Capacity costs are divided between primary, driven by coincident peak load, and secondary, driven by local non-coincident maximum demand. Customer access costs, covering new business and line extensions, connection equipment, and ongoing customer service, scale

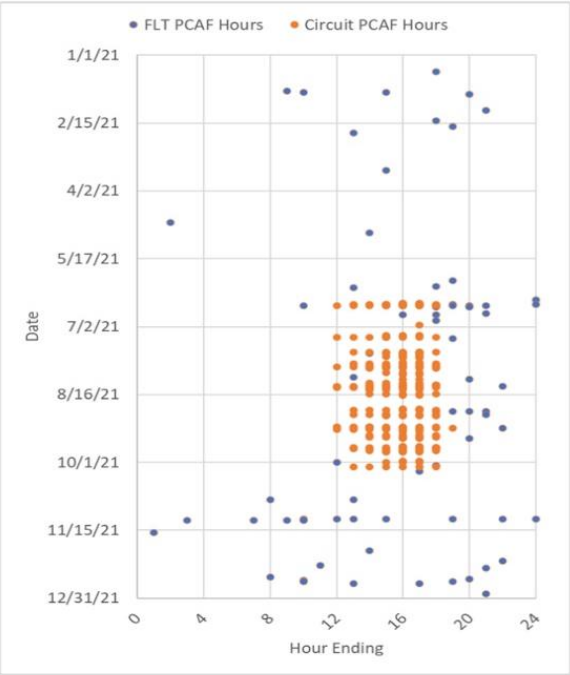
with the number and type of customers rather than load. **Table 2** summarizes each category and its cost driver.

Table 2. Cost Categories and Drivers

Category	Example costs included, different terms used	Cost Driver
Marginal Distribution Capacity (Primary)	Substations, Primary Feeders	Coincident peak load
Marginal Distribution Capacity (Secondary)	Secondary Feeders, Final Line/Service Transformers	FLT load, Effective Demand Factor, Design Demand
New Business & Line Extension	Line extensions, service laterals, new customer interconnections	Number of customers (by type/size)
Marginal Customer Access (Connection Equipment)	Service drop, meter	Number of customers (by type/size)
Marginal Customer Access (Customer Service)	Meter reading, billing, communications	Number of customers

PG&E's marginal cost study illustrates the divergence between primary and secondary cost drivers[15] (**Figure 5**). For a single sample circuit over the course of a year, the hours driving primary capacity cost (Circuit PCAF Hours) cluster tightly in summer and early fall afternoons. Those driving secondary capacity costs (Final Line Transformer PCAF Hours) scatter across nearly every hour and month, tracking the maximum demand of the few customers on that transformer rather than the system as a whole. A compensation program that includes secondary capacity costs in a payment targeting coincident peak reduction pays for a cost that coincident peak reduction does not avoid.

Figure 5. PG&E Primary and Secondary Load Drivers for Single Feeder



Avoided costs are a subset of marginal costs that DER grid services can actually realize. A DER that reduces or shifts load reduces the required system capacity, but does not change the cost of connecting or serving the customer. Therefore, customer access costs are excluded from the avoided cost calculation. The two capacity categories require distinct dispatch signals: primary capacity is avoided by reducing coincident peak load across thousands of customers, while secondary capacity is avoided only by reducing very local non-coincident maximum demand among a small group of customers (**Table 3**).

DER grid services can avoid a distribution investment only when they are of sufficient magnitude, located at the right feeder, timed to meet the distribution grid need (e.g., a local peak), and reliable enough for the utility to defer the capital investment with confidence. Many DER deployments satisfy some but not all of these conditions, and calibrating compensation to the marginal cost of serving new load rather than the avoided cost of a specific deferred investment will systematically overpay relative to the value actually delivered by DER grid services.

Table 3. Concepts for Average, Marginal, and Avoided Distribution Cost

Cost Category	Non-Marginal, Non-Load Related Costs		Marginal Costs			
	Embedded/ Sunk	Age Related Replacement	Primary Capacity	Secondary Capacity	New Business	Customer Access
	Existing Substation	Replace Aging Transformer	Add New Substation Transformer	Upsize Final Line Transformer	Line Extension To New Customer	Service Drop To Customer
Average	✓	✓	✓	✓	✓	✓
Marginal			✓	✓	✓	✓
Avoided			✓	✓ *		

**Avoiding secondary capacity costs relies on reducing non-coincident peak and connected load among a small number of customers, which is more challenging than reducing coincident peak load on the primary distribution system.*

System-wide vs. Locational Distribution Value

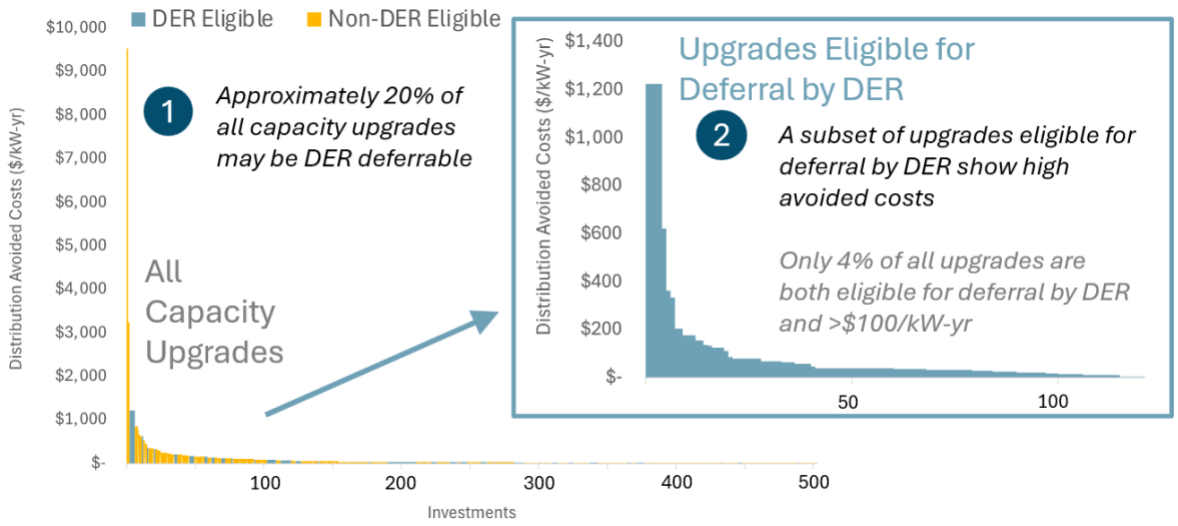
Marginal distribution cost studies produce a system-wide average cost per kilowatt of accommodating new load growth, an average that smooths over substantial variation in where investment is actually needed. Investment is triggered by load growth at specific network points: a feeder approaching its thermal limit, a substation nearing its capacity ceiling, or a planned project with a defined cost and in-service date. Across most of a service territory at any given time, existing distribution capacity is adequate, and the near-term marginal cost of additional load is low or zero.

That concentration of distribution marginal costs produces multiple distinct values that a compensation framework must treat separately. The system avoided cost is the average avoided cost across all locations, a defensible basis for a universal payment available wherever a DER operates. The locational deferral value is tied to an identifiable investment a DER can realistically defer, and it exists only where (1) there is an identified grid need, (2) that need is deferrable with DER, and (3) there is sufficient achievable DER adoption potential at the right location. Additionally, the value of deferred investment is unique for each location.

Some stakeholders reasonably argue that marginal cost studies understate distribution value, since DER ease loading across the network and can defer investments that would never be identified in a specific planning study. Broad load reductions sustained over long horizons do reduce the overall size of the distribution grid a utility must build, up to a point. However, that value is diffuse and not robustly quantifiable or verifiable. Setting a system-wide payment for all DERs too high risks increasing, rather than reducing, rates.

Paying the multiple values through separate signals resolves this. The system avoided cost is modest and uniform, grounded in a territory-wide assessment that includes the large share of the network with no near-term need, which keeps it stable across planning cycles and consistent with how avoided cost is used in resource planning and energy efficiency valuation. The locational deferral value is paid only where a deferrable grid need exists, through a separate signal reconciled with the system avoided cost. That signal is netted against the baseline payment when the two would pay for the same deferral, and additive when they reflect distinct investments. Setting the universal rate on costs observed only in constrained areas would invert this logic, paying every participating DER as though it avoided a planned distribution investment.

Figure 6. A Small Percentage of Grid Needs Have a High Value and Are Avoidable by DER: Data from Annual California IOU Grid Needs Assessments[16]



E3 analysis of data from PG&E, SCE and SDG&E Grid Needs Assessment (GNA) and Distribution Deferral Opportunity Reports (DDOR) shows that 1) a small percentage of distribution feeders have identified grid needs with a high deferral or avoided cost value, and 2) a small percentage of those grid needs can be deferred by DER. Locational distribution value is concentrated in this small subset of the system that cannot be effectively targeted by a single system-wide incentive.

Distribution Effective Capacity

Distribution effective capacity (Dx-ELCC) is the capacity a DER or aggregation can be counted on to deliver toward a grid need at a specific feeder, transformer, or circuit segment during the distribution critical hours. It is the distribution analog to the effective load carrying capability system operators use to credit bulk-system resources. Bulk ELCC is a system-wide, location-blind measure set against a system reliability standard, while Dx-ELCC is location-specific and set against the local peak and the design criteria of the equipment that

serves it. A resource's Dx-ELCC and its bulk ELCC can diverge sharply, because the distribution critical hours at a given location often do not coincide with the bulk-system peak. The distribution critical hours are no longer confined to summer afternoons; as distributed generation and electrification reshape net load, they now include both peak-demand hours and the hosting-capacity conditions created by high midday distributed generation.

The share of nameplate or enrolled capacity that can be relied on at the location during critical hours is the dependability factor; nameplate capacity multiplied by the dependability factor equals distribution effective capacity. It reflects that DER are customer assets operated primarily for comfort and cost rather than to serve the grid, and it cannot draw on the smoothing of large numbers available on the bulk system.

Three attributes, each assessed against local rather than system conditions, determine the dependability factor:

- **Coincidence:** the alignment between the resource's output and the timing of the local peak, so that only the reduction occurring during the distribution critical hours counts.
- **Availability**: the share of the enrolled resource actually present and responsive when called, online and communicating, not opted out, and not fatigued by prior dispatch.
- **Duration:** whether the resource can sustain its reduction across the full length of the local need, given energy or state-of-charge limits.

Compensation attaches to distribution effective capacity valued at the locational distribution avoided cost, with these attributes converting nameplate or enrolled capacity into the reliable capacity delivered where and when the grid needs it.

Coincidence

Many DER programs compensate distributed resources for a combination of generation value, capacity or resource adequacy value, and distribution deferral value, reflecting the stackable grid services a well-sited, well-dispatched DER can deliver, and each component has a defensible rationale. In most programs today, the dispatch signals sent to earn these credits are drawn almost entirely from bulk-system conditions or fixed time-of-use windows that do not reliably coincide with distribution feeder peaks. **Figure 7** shows why: for a single location, the generation, transmission, and distribution avoided capacity costs these credits represent concentrate in different hours, so no single bulk signal or time-of-use window captures all three at once. **Figure 8** shows a related problem at the distribution level: feeders across the system peak at various times, including late evening, early evening, and midday, so a signal tied to a system-wide peak misses the specific feeder and hour where a deferral is needed.

Figure 7. Hourly Generation, Transmission, and Distribution Avoided Costs for Three Summer Months (Santa Rosa, CA)

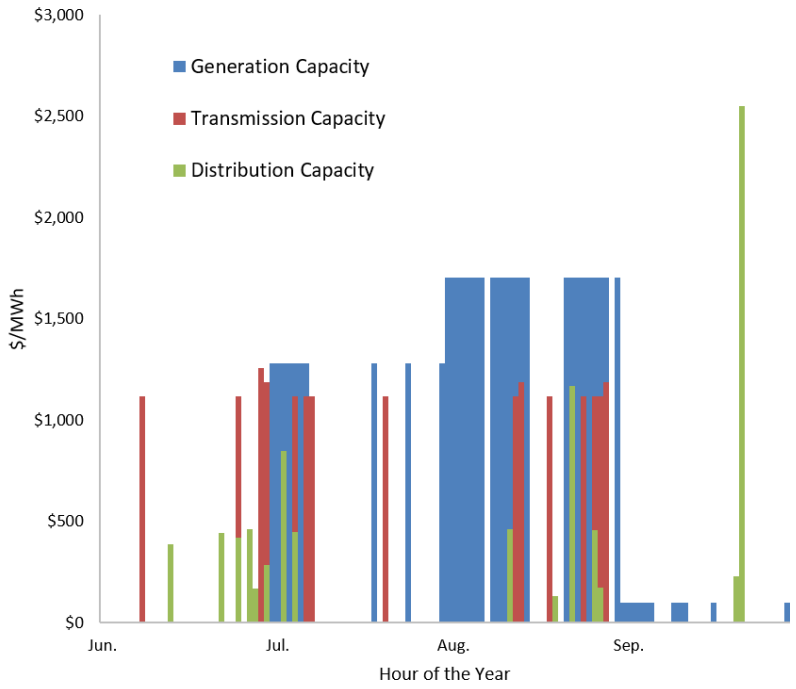


***Figure 7** shows hourly generation, transmission, and distribution avoided capacity costs across the summer months for Santa Rosa, in Northern California. Each is driven by a different quantity: generation by load net of renewable output, transmission by the coincident peak at the transmission level, and distribution by coincident peak load at the primary distribution substation. The three values concentrate in different hours and cannot be readily stacked in a single TOU period.*

Figure 8. Illustrative Diversity of Feeder Peaks for Municipal Utility in the Western U.S.

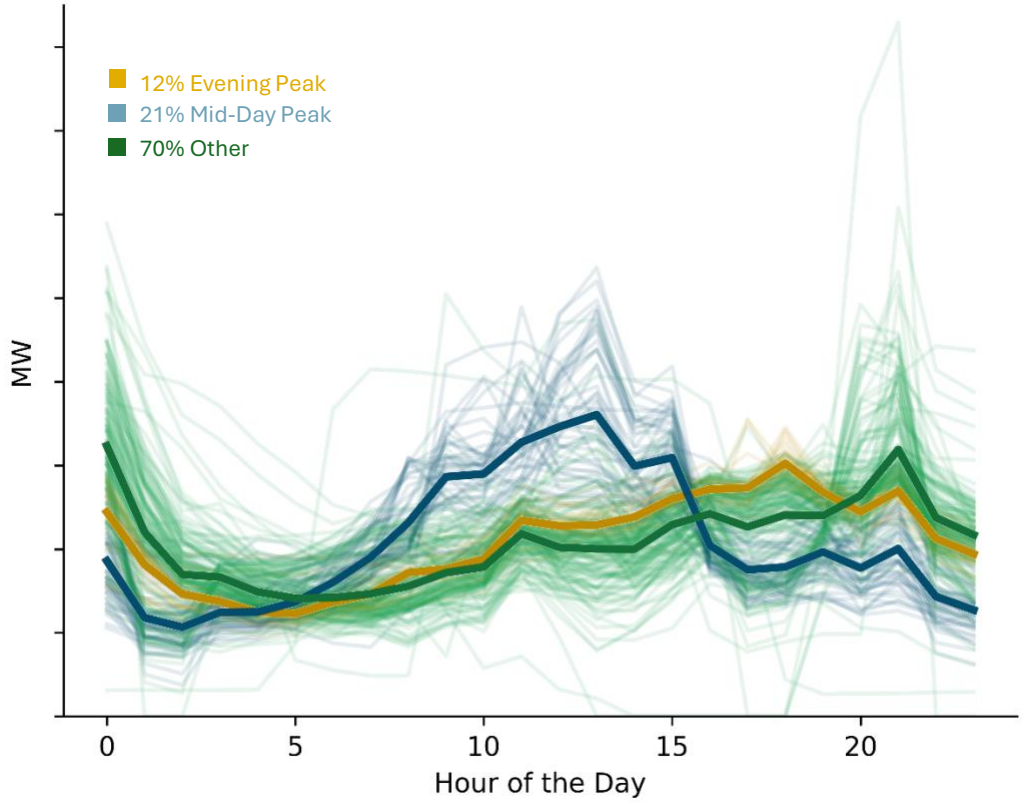


Figure 8 *shows 24-hour forecasted feeder load shapes for 230 feeders for a municipal utility in the Western U.S. with electrification. Approximately 12% of substation banks peak in the evening (4-8 PM) (yellow), 21% peak midday (10 AM - 4 PM) (blue), and 70% peak in other hours (green). Note that in this particular case, the off-peak period starts at midnight, leading to a secondary peak with managed EV charging in the middle of the night.*

A DER dispatched to maximize revenue during high-priced bulk hours reduces generation costs, but it does not necessarily reduce load on the constrained feeder during the hour when a distribution upgrade or deferral is needed. Crediting that resource for distribution deferral, therefore, overstates the distribution value actually delivered and misses the opportunity to provide the service at the circuit and hour where the value exists. Dispatching DER based on local grid conditions is essential to realizing avoided distribution costs for ratepayers.

Availability

Distributed resources are first customer assets, acquired and operated for comfort, convenience, and cost rather than to serve a grid need, and they must be evaluated as such. Customer participation, tolerance for repeated dispatch, and daily routine set the practical ceiling on how much of an enrolled resource the grid can rely on, and that ceiling shifts with

weather, season, and the device's physical limits. A vehicle-to-grid program must quantify peak load impacts by assuming how many enrolled vehicles are unavailable at any given event because they are not home and plugged in.

Deferring an investment requires a firm commitment to deliver during defined dispatch windows, accountability backed by real consequences for non-performance, and measurement that confirms the committed reduction was delivered.

Because some enrolled DER will decline to respond, underperform, or drop out, the enrolled capacity needed to defer an investment with confidence significantly exceeds the target reduction. A program must procure a buffer above the identified grid need and calibrate it to observed attrition, refining the assumption as performance data accumulate. The margin for the additional DER program capacity that must be enrolled (e.g., 22, 25, or 30 MW) to confidently achieve 20 MW of load reduction is a question planners will need to answer for each DER type. Compensation should then be set at a portion of realized avoided cost, paying for the capacity actually delivered rather than the capacity enrolled.

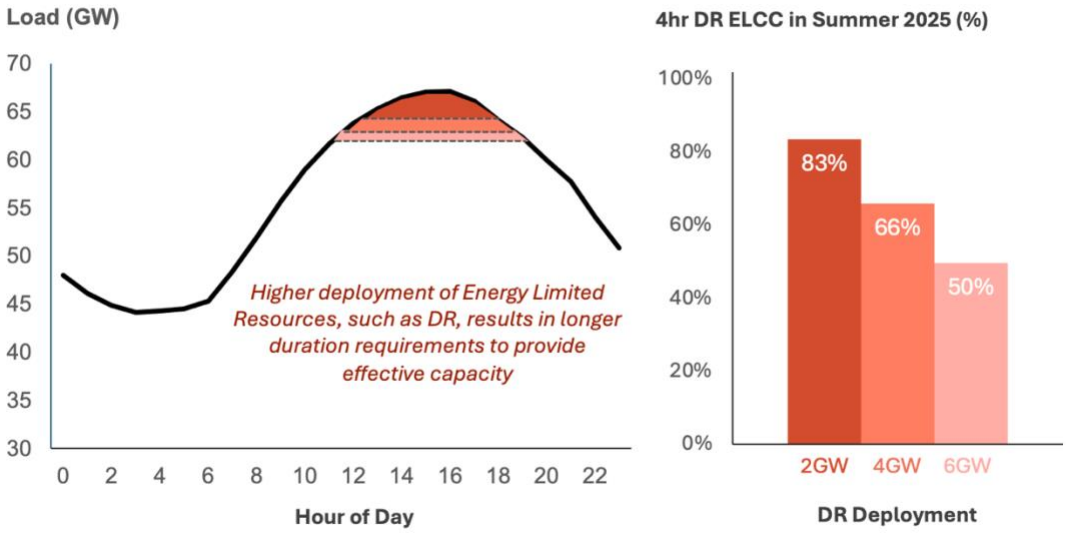
Duration

A distribution grid need is rarely a single hour. A feeder's critical hours can persist across an afternoon and, during multi-day heat waves, recur over several consecutive days, so a resource provides effective capacity only if it can sustain its reduction across the full duration of the event. Energy and state-of-charge limits bind, so a four-hour battery or a managed-charging window that covers a short peak may fall short of a six-hour feeder peak or a three-day event, delivering less effective capacity than its nameplate implies.

The time required to deliver a given reduction increases as DER adoption scales across a feeder and flattens the peak load shape. A modest amount of storage or demand response can flatten a short, sharp peak, but as more DER is added, the residual peak broadens, and each additional DER increment must sustain its reduction over a longer window to reduce peak load. For example, **Figure 9** shows the summer effective capacity of a 4-hour demand response (DR) resource in the Southwest Power Pool declining from 83% of nameplate at low penetration to 50% as adoption grows. Precisely the same decline of effective capacity with increasing DER penetration occurs on the distribution system.

Effective capacity must therefore be assessed at the penetration expected on the feeder, not at the level where the first units enter, and revisited as adoption grows. Crediting a short-duration resource against a sustained need, or crediting early-entrant performance as adoption scales, overstates the capacity a program can rely on to defer the investment.

Figure 9. Declining Effective Peak Load Reduction From DR in Southwest Power Pool[17]



Paying compensation based on nameplate or enrolled megawatts, without adjusting for reliable dispatch during the critical hours that drive the grid need, overcompensates a resource's contribution and provides no basis for distinguishing resources that are more or less reliable during critical feeder peak hours. Distribution planning studies assess this by evaluating reliable, visible output against the feeder's critical hours and the consequences of unavailability, the distribution-level counterpart to bulk-system ELCC. Methods for this adjustment are not yet standardized in planning tools, as ELCC is for bulk-system capacity models. DER program designers developing LVDER constructs will need to establish an equivalent framework that specifies how local capacity contribution is measured for different resource types and is revisited as system conditions and performance evolve.

Whether this value is captured depends on program design. Compensation that scales with the location, timing, and reliability a resource actually delivers rewards the resources that defer investment, while compensation indifferent to those conditions pays resources that defer nothing and shifts cost to non-participating customers.

A Framework That Works

Many DER programs that include LVDER compensation make one or more of five structural design choices that create systematic risk of overcompensation:

1. Payments anchored to an administratively determined marginal cost estimate rather than to verified avoided costs tied to deferrable upgrades.
2. Compensation available system-wide rather than targeted to locations with identified grid needs.
3. Dispatch windows that follow bulk-system peak periods rather than local feeder conditions, so resources discharge at the wrong time to defer distribution investment.
4. Payment based on nameplate or enrolled capacity rather than the effective load reduction delivered during critical hours.
5. Long commitment terms that lock these structures in, preventing recalibration as grid conditions change.

Individually, these choices may be grounded in policy objectives to launch a nascent market, keep enrollment simple, or give developers the revenue certainty needed to finance investment. In combination, however, they direct payment to resources that do not avoid distribution investment and lock in high compensation as the DER fleet grows. The framework proposed here resolves each in turn, building on the three principles established earlier: (1) compensate below verified avoided cost, (2) pay for measured performance rather than enrollment, and (3) streamline programs onto common standards. Its core is a two-tier compensation structure, a modest system-wide payment available to every DER, and a targeted locational payment available only where a resource defers an identified investment, set on a revenue term long enough to finance yet short enough to recalibrate.

A survey of programs with distribution-value compensation is summarized in **Table 4** and further detailed in **Appendix A.**

Table 4. LVDER Program Design Choices Across Jurisdictions (See Appendix A)

Program (status)	System-wide payment	Sys. basis	Locational payment	Loc. basis	Set by	Revision trigger	Dispatch window	Compensation basis	Commitment term
Illinois **CRGA VPP & DG rebate (P.A. 104-0458, sec.16-107.6/.9)** **2026-2028**	$300/kW DG & $300/kWh storage now, stepping to $250 after 2029 +$10/kW-avg-dispatch floor	Administrative	authorized for additive services / VPP tariff (sec.16-107.9) amounts TBD	TBD	Legislation Regulator	Statutory defined "Threshold Date" will occur in 2028 transitioning to ICC based formula	Fixed statutory 4-6 pm BTM 4-7 pm FOM weekdays Jun-Sep (PJM peak)	Enrolled MW + performance ($/kW avg dispatch)	5-yr enrollment (re-enrollable)
New York **VDER DRV/LSRV (PSC Case 15-E-0751)** **in effect**	DRV per utility $/kW-yr	Marginal cost	Yes (LSRV) per-utility adder at designated substations finite MW per zone	Marginal cost	Regulator Utility tariffs	10-yr vintage lock; updates with PSC-approved MCOS studies	Fixed bulk-peak window Varies by utility	Metered kWh exports (performance)	10-yr vintage lock
Connecticut **Energy Storage Solutions (PURA 25-08-05)** **in effect (Apr 2026)**	Enroll $30/kWh res, $10/kWh priority comm; perf (fixed 10 yr) $300 std / $450 underserved / $550 low-income per kW-yr	(basis not stated)	Yes $130/kWh residential grid-edge enrollment incentive	Administrative (basis not stated)	Regulator Utility proposal	PURA docket	Event-based 30-60 summer 1-10 winter	Enrolled MW + performance payment	10 years
Colorado **Aggregator VPP (SB 24-218; CPUC 25A-0061E)** **in effect (Dec 2025)**	Gen $134 + trans $21 /kW-yr; aggregate ~$264.56/kW Yr1 (incl. distribution)	Avoided cost (Year 2 market-indexed)	Yes distribution $69/kW-yr in DSP-constrained (>75% planning limit) areas	Avoided cost (DSP feeders/ banks)	Legislation Regulator Utility Filing	5-yr fixed then reset; Yr2 market-indexed	Flexible, year-round 60 (summer-only) 80 (year-round) 4-hr events	Measured baseline-vs-actual	5 years
Hawaii **Battery Bonus; BYOD (PUC 2019-0323)** **in effect**	Battery Bonus $850/kW upfront + $5/kW-mo BYOD L1 $100/kW BYOD+ $400 (non-LMI)/$800 (LMI) per kW	Administrative	No	(basis not stated)	Regulator Utility Filing	MW caps BB 55 MW BYOD 50 MW, 25 LMI + set timelines	Scheduled BB: 6:00-8:30 pm BYOD: 2 hr/day	BB: Firm scheduled capacity BYOD: upfront + export credit	BB: 10-yr BB BYOD L1: 3-yr BYOD+: 5-yr
Delaware **Delmarva LDR + BYOD/BYOB/DLC (Docket 25-1554)** **proposed 2027-2029**	BYOD $25/device + $40/yr; BYOB $125/kW-yr + event kWh; DLC 2.0 $40/$60/$80/Year Smart Charge $5/$10 mo.	(basis not stated)	Yes: Proposed: LDR bonus $100/kW BYOD +$25/yr (DLC excluded)	Proximity-based (basis not stated)	Regulator Utility Filing	Not stated (2027-2029 portfolio)	Not stated DR events	Enrolled MW or Device + capacity ($/kW) + event kWh payment	Not stated
Maryland **DRIVE Act (HB 1256; PSC Cases 9761/9778)** **program not final**	Potomac Edison proposed up to $300/kW-yr	TBD by PSC "cover cost of DER to owner or aggregator"	Yes PSC directive (Case 9761) structure not final	TBD by PSC	Legislation Regulator	2-yr pilots (PSC directive) 2% peak enrollment cap	Not specified (>=30 events/yr per statute)	Pay for performance	2-yr pilots; 5-yr min for upfront-incentive customers
Nevada **NV Energy GSR-E/GSR-C (Dockets 25-10012/13)** **proposed**	Distribution $25/kW-yr & Generation and Transmission $120/kW-yr, x 30% Capacity Resource Rate	Marginal cost	Yes: Proposed: location-specific Distribution Node rate; default system-wide	Marginal cost	Utility Filing	Annual requalification	Event-based no fixed window	Performance vs customer-specific baseline	Annual default; optional multi-year (<=10 yr)

Note: "Basis not stated" are dimensions the source materials do not characterize for that program

Compensate Below Avoided Cost for Ratepayer Benefit

Two Tiers: a System-Wide Baseline and a Targeted Locational Payment

The framework has two tiers: a modest system-wide payment available to every DER, and an LVDER payment available only where a resource defers an identified investment.

The baseline payment compensates for the modest distribution value that broad load reduction delivers system-wide. A properly specified long-run avoided distribution cost captures the value of system-wide load reduction over time, including investment that load growth would otherwise require but may not appear in any planning study or be attributed to a specific project. Because that value is diffuse and uniform across locations, the measure rests on avoided cost rather than the marginal cost of service: the present value of the distribution investment that expected load growth would otherwise drive, expressed per kilowatt of incremental load and averaged across the service territory. This system-wide value applies to the primary distribution system, whose capacity costs are driven by the coincident peak load of many customers, rather than to the secondary system, whose costs are driven by the non-coincident maximum demand of individual customers. Most of the network carries no near-term investment need, so the territory-wide average is modest by design, and every customer participating in the DER program receives it regardless of location or proximity to a constrained feeder, giving developers a predictable revenue basis and supporting market entry. NYSEG's system-wide Demand Reduction Value (DRV) of $29.67 per kW-year, paid to every eligible resource in its territory, illustrates this concept, though the DRV in New York is derived from each utility's marginal cost of service study, rather than from the verified avoided-cost measure recommended here.

To prevent paying twice for the same value, the targeted LVDER component applies only when an identified grid need can be deferred and is priced at the area-specific avoided cost of the deferrable investment. Where the baseline and the locational LVDER payment would compensate for the same underlying deferral value, the two payments are reconciled in one of two ways: the LVDER payment is either set incremental to the baseline, or the resource receives the higher LVDER payment in place of the baseline. Either way, total compensation for that deferral equals its area-specific avoided cost rather than that cost plus the baseline floor. Where no distribution grid need or constraint exists, the baseline stands alone. Compensation should also clear the opportunity cost of any bulk-market revenue a resource forgoes by dispatching to local needs; where the avoided distribution cost cannot cover that opportunity cost, the deferral is not cost-effective, and the resource is better left serving the bulk system. New York currently sets its locational adder above the baseline rather than net of it, with NYSEG adding a Locational System Relief Value (LSRV) of up to $56.26 per kW-year at designated substations (again based on the utility's marginal cost of service study).

Credit Only Value Beyond the Retail Rate

LVDER compensation should pay only for the incremental grid response a resource provides, over and above what its retail rate, NEM, or NBT already induces. A DER whose load reduction or export is already elicited and compensated under an existing tariff or program should not be paid again for the same response. This ensures that the locational payment accrues only to the incremental dispatch a resource delivers in response to the program. A resource whose response is already fully induced and compensated under another tariff or program is therefore ineligible for an additional LVDER payment. Where a resource's retail rate is flat, or its on-peak TOU periods diverge from the distribution critical hours, the rate does not elicit load reduction for local distribution needs, so the response is incremental and the locational payment is warranted.

A Revenue Term Long Enough to Finance, Short Enough to Recalibrate

Distribution needs change as electrification reshapes feeder load and DER adoption saturates the deferral opportunity on a given feeder, so a need that justifies a locational payment today may be resolved by the next planning cycle. This resolution can include successful deferral of the infrastructure upgrade to the planned in-service date, thereby eliminating the need for additional grid mitigation from DER grid services. A framework that fixes dispatch windows, performance requirements, and enrollment at inception keeps paying for deferral after the underlying need has passed, and long compensation lock-ins prevent recalibration as conditions evolve. Some revenue certainty is nonetheless necessary, since developers and customers will not finance the underlying investment without a reasonably firm revenue basis. The design question is where to set the commitment term, and the five-year horizon discussed earlier balances financing needs against periodic recalibration. A term that outlasts the horizon over which distribution needs can be projected converts a time-limited deferral payment into a durable entitlement. This same dynamic made net-metering compensation so difficult to unwind.

How far ahead the capacity must be secured shapes both the risk and the cost. Engineering, procurement, and construction of distribution typically begin about three to five years before the capacity is needed, so a resource intended to defer an upgrade must meet a threshold level of planning confidence before the need arises. A utility can reduce deliverability risk by procuring the full quantity early, but it then pays for capacity in years before the investment is actually deferred. The reconciling principle is that the net present value of the performance payments over the life of the commitment should be meaningfully lower than the cost of the project deferred, so procuring early lowers the annual incentive and spreads it over more years rather than adding to total cost. The timing and shape of the payout can be flexible to accommodate what customer adoption requires.

Pay for Accurately Measured Performance (Not Enrollment)

Eligibility and Caps: Compensate Only Where, and as Much as, Deferral Is Achievable

The locational tier limits eligibility to feeders with an identified, deferrable grid need and caps enrollment at the quantity needed to defer the specific investment, as New York's VDER tariff does in setting a megawatt limit for each qualifying LSRV substation. Beyond that quantity, additional DER provides no incremental distribution value.

The opposite risk is that too few capacity units are enrolled, leaving the deferral short, so the utility must still build the upgrade, and ratepayers pay twice, once for the DER compensation and once for the distribution upgrade. Whether a resource will perform well enough to mitigate the forecasted need can take years to establish, so a shortfall may not become apparent until the window to defer the project has nearly closed.

Committing to payments before knowing whether enough capacity will enroll is a risk without a clear answer. Each participating resource is paid firmly for its measured performance rather than made contingent on the aggregate deferral, which avoids penalizing early movers but leaves ratepayers exposed if the needed quantity does not materialize before the project must proceed. One mitigation is to discount deferral payments for the possibility of compensated but unrealized deferral, keeping the program cost-effective overall.

Dispatch Windows Set to Distribution Peaks, Not Bulk-System Periods

Dispatch windows in many programs follow bulk-system time-of-use periods, which do not reliably coincide with distribution peaks, and shoulder-hour peaks outside those periods can drive feeder investment even when no resource is dispatched to meet them. DER program dispatch windows should instead be defined by local load shapes and the specific critical hours that drive investment at each constrained feeder. Because these windows do not track static time-of-use rates, dispatch is communicated through utility or aggregator control signals rather than relying on customers to respond to price. Performance requirements, including minimum dispatch duration, response time, and availability, should be set at levels sufficient to qualify a resource as a reliable planning resource for deferral. The program should include built-in provisions to update both the dispatch windows and the performance requirements as load shapes and DER adoption change.

Payment for Effective Capacity Delivered During Critical Hours

Paying on nameplate or enrolled megawatts overcompensates resources that cannot reliably dispatch during the critical hours that drive distribution investment, rewarding

enrollment rather than performance. LVDER compensation should instead be a function of the effective local capacity a resource provides, the distribution-level analog to ELCC described earlier, crediting demonstrated performance during those hours. Effective capacity can be estimated *ex ante* from program design to set expected payments, then trued up *ex post* against the resource's actual response during called events, so credited capacity tracks delivered performance. Where several programs or customer resources are orchestrated across a longer window to hold down a feeder peak, the compensation pool should reflect the deferral actually achieved rather than the sum of individual nameplate ratings, and performance-based payments tied to measured dispatch outcomes are preferable to a fixed, administered rate.

Crediting effective capacity requires a measurement method that distribution planning has not yet standardized, unlike bulk-system planning, which standardizes ELCC. LVDER program designers will need to establish a distribution equivalent that specifies how local capacity contributions are measured for each resource type, and this should be revisited as system conditions and performance evolve. That framework derates enrolled capacity in two distinct steps: first, a dependability derate from nameplate to distribution effective capacity, reflecting how reliably a resource reduces load during the critical hours; second, a procurement buffer above the target reduction, sized to the share of enrolled resources that decline, underperform, or drop out. Applied together, the two steps ensure the delivered, derated capacity still clears the reduction required by the deferral. Directly metered resources, such as battery storage, can be credited from observed dispatch, while resources whose reduction is inferred against a counterfactual, such as smart thermostats, require a trusted statistical or A/B-testing baseline to isolate the grid impact from ordinary use.

Streamline and Consolidate Programs

DER represents a large market in aggregate, but the benefit that reaches customers and ratepayers is only what remains after each link in the delivery value chain takes its share of revenue or costs. As **Figure 10** illustrates, the total system benefit is drawn down by utility overhead and administration, IT infrastructure such as AMI and DERMS, program management and aggregation, customer marketing and recruitment, incentive payments, and enabling hardware before any net benefit remains. If the stacked cost of these links is too high, the resource is not cost-effective relative to the utility investment it is meant to defer, however large the underlying opportunity appears. Whether that chain is efficient depends on two things: whether each link earns its margin by delivering value, and whether its cost is largely fixed, independent of the number of participating units, or variable and scaling with enrollment. Fixed costs such as IT infrastructure and program administration fall on a per-unit basis as enrollment grows, which is where consolidating overlapping

programs and standardizing enrollment, dispatch, and measurement does the most to widen the net benefit and let the resource scale cost-effectively

Interoperable, open standards and robust APIs

A utility often starts with a single vendor, a DERMS provider, program administrator, or aggregator platform, to run enrollment, telemetry, and dispatch. This becomes a liability as DER pathways multiply, since each new program either limits participation to the devices and aggregators the incumbent supports or requires a bespoke integration for every additional vendor. Allowing several aggregators to serve the same grid need introduces market competition, but at the cost of more complex coordination on the part of the utility.

Standardized, open-enrollment interfaces, dispatch protocols, and measurement formats, as some utilities have adopted through OpenADR, allow a utility to qualify multiple vendors against a single technical specification rather than each vendor's proprietary architecture, so it can add or replace a provider without rebuilding core systems. Because locational compensation depends on verified measurements across many locations, vendors, and technologies, policymakers should consider encouraging or requiring these standards at the state level rather than leaving them to individual utility-vendor negotiations. A market that readily incorporates multiple vendors without bespoke integration costs is better positioned to scale cost-effectively.

Enable DER to stack and co-optimize grid services.

Incorporating locational compensation into existing programs lets a single resource stack grid services, earning distribution deferral value alongside bulk-system or reliability value where those services are compatible. Because a resource cannot always deliver a distribution service and a bulk-system service on the same day, stacked value is not fully additive, and compensation for stacked services should reflect the frequency with which both can actually be provided rather than assume each is earned in full. A common enrollment and dispatch platform directs each resource to its highest-value use, serving the local distribution need first and releasing the resource to the bulk system when no distribution constraint binds. Co-optimizing in this way raises the revenue a resource earns from a given investment and improves utilization of enrolled capacity, strengthening the third-party business case without adding ratepayer cost.

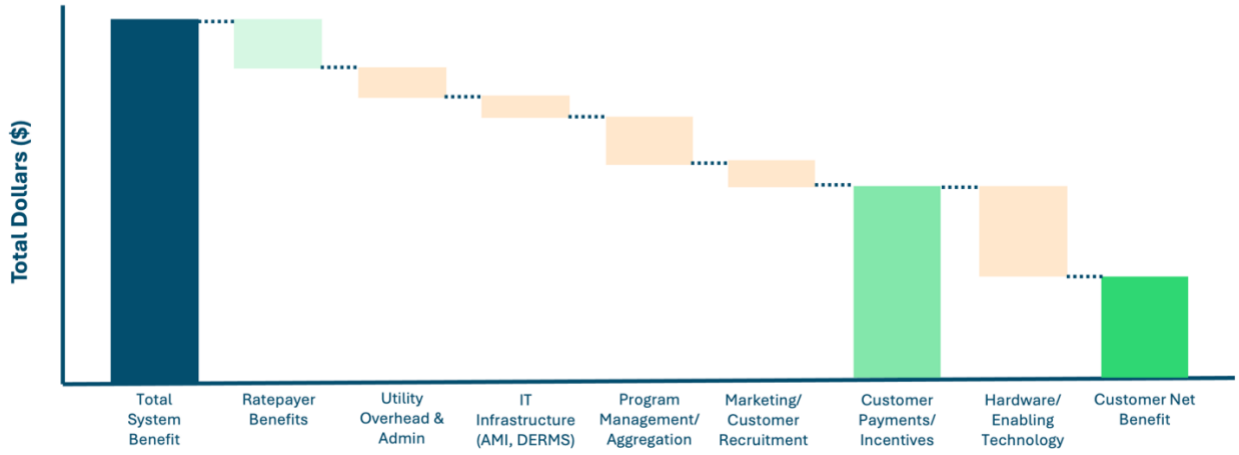
Balance enrollment and performance risk

Utilities will need to work with aggregators, vendors, and service providers to innovate on customer-facing products or to enroll and operate mass-market flexible load at the scale distribution deferral requires. The model has to work for both the utility needing verified,

dispatchable capacity it can count on to defer an upgrade, and the third party needing revenue predictable enough to finance customer acquisition and hardware, yet still anchored to verified avoided cost. Intermediaries must earn their margin only where they add net value, aggregating many small resources and handling enrollment, measurement, and dispatch more cheaply than customers or the utility could alone.

Someone must also bear the risk that enrollment falls short or that enrolled resources underperform, and where that risk lands determines whether a program can be financed at all. Placing it on a third-party aggregator is attractive in principle, since the aggregator recruits and manages the fleet and is paid only when it delivers the deferral, insulating ratepayers from paying for value that does not materialize. In practice, bearing deferral risk requires credit and collateral that few aggregators can raise at the scale a substantial grid needs. The industry's history is cautionary: demand-response aggregators such as Comverge and EnerNoc have been acquired and no longer operate in their original capacity. Aggregators, device vendors, and software providers have also tended to overpromise on what their platforms can reliably deliver. Hence, a program that assumes seamless orchestration is likely to underestimate the budget and enrollment needed to hit its target. Penalties large enough to protect the deferral raise the credit burden, limiting participation, so the program design must strike a balance between the predictability third parties need to invest, and the pay-for-performance discipline ratepayers need.

Figure 10. Total Benefits of an LVDER Program Must Cover Many Slices of the Pie



Conclusion: Establishing Durable Pathways for LVDER Compensation

The distribution grid will carry much of the new load that vehicle and building electrification adds over the coming decade, and the resources enrolled in DER programs now will still be under contract when that load arrives. The compensation rules set today will govern a DER fleet several times larger than today's, and they will still bind when the electrification load they are meant to serve arrives. Getting the basis right while enrollment is small is far easier than unwinding it after financing terms, vendor business models, and customer expectations have hardened, as the net-metering experience made plain and as distributed storage, now scaling even faster than early rooftop solar, threatens to repeat.

The two-tier framework proposed here prices each component of compensation to a verified grid service value: a modest system-wide payment for the diffuse value of broad load reduction, and a locational payment, reconciled with that baseline to avoid paying twice for the same deferral value. The locational LVDER payment is available only where an identified need can be deferred and only up to the quantity that defers it, credited to the effective capacity a resource delivers during the hours and on the feeders that drive investment. Revenue terms long enough to finance and short enough to recalibrate keep the payment from outliving the need that justified it.

Pricing to verified, locational, performance-based value is necessary but not sufficient for ratepayer benefit. Ratepayers come out ahead only when total avoided costs exceed total payments, the net-benefit test any program should meet, which is why compensation is set below avoided cost by design and paid only for value delivered at the point of measurement. That discipline protects ratepayers even where near-term deferral opportunities prove thin: the locational tier applies only at the few feeders with a deferrable need, the system-wide baseline stays modest, and the framework pays nothing for value it cannot verify, so it scales down gracefully rather than manufacturing savings that are not there.

The task is not to promote DER adoption but to compensate the grid services distributed resources provide, so that it tracks the value actually delivered. Establish a solid foundation now, and a durable market for distributed resources and protected affordability for all ratepayers will follow.

Appendix A. Survey of LVDER Program Attributes in the U.S.

Many DER programs that include LVDER compensation include one or more of five structural design choices that create systematic risks of overcompensation:

1. Payments are anchored to an administratively determined marginal cost estimate rather than to verified avoided costs tied to deferrable upgrades.
2. Compensation is typically made available system-wide rather than targeted to locations with identified grid needs.
3. Dispatch windows follow bulk-system peak periods rather than local feeder conditions, so resources may discharge at the wrong time to defer distribution investment.
4. Payment is based on nameplate or enrolled capacity rather than the effective load reduction delivered during critical hours.
5. Long multi-year commitment terms lock these structures in, preventing recalibration as grid conditions change.

Each subsection below identifies the design choice that produces risk in current programs and examines the approaches that more recently developed programs have adopted to address it.

Table 5. LVDER Program Design Choices Across Jurisdictions

Program (status)	System-wide payment	Sys. basis	Locational payment	Loc. basis	Set by	Revision trigger	Dispatch window	Compensation basis	Commitment term
Illinois **CRGA VPP & DG rebate (P.A. 104-0458, sec.16-107.6/.9)** **2026-2028**	$300/kW DG & $300/kWh storage now, stepping to $250 after 2029 +$10/kW-avg-dispatch floor	Administrative	authorized for additive services / VPP tariff (sec.16-107.9) amounts TBD	TBD	Legislation Regulator	Statutory defined "Threshold Date" will occur in 2028 transitioning to ICC based formula	Fixed statutory 4-6 pm BTM 4-7 pm FOM weekdays Jun-Sep (PJM peak)	Enrolled MW + performance ($/kW avg dispatch)	5-yr enrollment (re-enrollable)
New York **VDER DRV/LSRV (PSC Case 15-E-0751)** **in effect**	DRV per utility $/kW-yr	Marginal cost	Yes (LSRV) per-utility adder at designated substations finite MW per zone	Marginal cost	Regulator utility tariffs	10-yr vintage lock; updates with PSC-approved MCOS studies	Fixed bulk-peak window Varies by utility	Metered kWh exports (performance)	10-yr vintage lock
Connecticut **Energy Storage Solutions** **(PURA 25-08-05)** **in effect (Apr 2026)**	Enroll $30/kWh res, $10/kWh priority comm; perf (fixed 10 yr) $300 std / $450 underserved / $550 low-income per kW-yr	(basis not stated)	Yes $130/kWh residential grid-edge enrollment incentive	Administrative (basis not stated)	Regulator Utility proposal	PURA docket	Event-based 30-60 summer 1-10 winter	Enrolled MW + performance payment	10 years
Colorado **Aggregator VPP** **(SB 24-218; CPUC 25A-0061E)** **in effect (Dec 2025)**	Gen $134 + trans $21 /kW-yr; aggregate ~$264.56/kW Yr1 (incl. distribution)	Avoided cost (Year 2 market-indexed)	Yes distribution $69/kW-yr in DSP-constrained (>75% planning limit) areas	Avoided cost (DSP feeders/ banks)	Legislation Regulator Utility Filing	5-yr fixed then reset; Yr2 market-indexed	Flexible, year-round 60 (summer-only) 80 (year-round) 4-hr events	Measured baseline-vs-actual	5 years
Hawaii **Battery Bonus; BYOD** **(PUC 2019-0323)** **in effect**	Battery Bonus $850/kW upfront + $5/kW-mo BYOD L1 $100/kW BYOD+ $400 (non-LMI)/$800 (LMI) per kW	Administrative	No	(basis not stated)	Regulator Utility Filing	MW caps BB 55 MW BYOD 50 MW, 25 LMI + set timelines	Scheduled BB: 6:00-8:30 pm BYOD: 2 hr/day	BB: Firm scheduled capacity BYOD: upfront + export credit	BB: 10-yr BB BYOD L1: 3-yr BYOD+: 5-yr
Delaware **Delmarva LDR + BYOD/BYOB/DLC** **(Docket 25-1554)** **proposed 2027-2029**	BYOD $25/device + $40/yr; BYOB $125/kW-yr + event kWh; DLC 2.0 $40/$60/$80/Year Smart Charge $5/$10 mo.	(basis not stated)	Yes: Proposed: LDR bonus $100/kW **B**YOD +$25/yr (DLC excluded)	Proximity-based (basis not stated)	Regulator Utility Filing	Not stated (2027-2029 portfolio)	Not stated DR events	Enrolled MW or Device + capacity ($/kW) + event kWh payment	Not stated
Maryland **DRIVE Act (HB 1256; PSC Cases 9761/9778)** **program not final**	Potomac Edison proposed up to $300/kW-yr	TBD by PSC "cover cost of DER to owner or aggregator"	Yes PSC directive (Case 9761) structure not final	TBD by PSC	Legislation Regulator	2-yr pilots (PSC directive) 2% peak enrollment cap	Not specified (>=30 events/yr per statute)	Pay for performance	2-yr pilots; 5-yr min for upfront-incentive customers
Nevada **NV Energy GSR-E/GSR-C** **(Dockets 25-10012/13)** **proposed**	Distribution $25/kW-yr & Generation and Transmission $120/kW-yr, x 30% Capacity Resource Rate	Marginal cost	Yes: Proposed: location-specific Distribution Node rate; default system-wide	Marginal cost	Utility Filing	Annual requalification	Event-based no fixed window	Performance vs customer-specific baseline	Annual default; optional multi-year (<=10 yr)

Note: "Basis not stated" are dimensions the source materials do not characterize for that program.

Compensation Basis: Marginal versus Avoided Cost

The Problem: Marginal Cost Estimation Without Deferral Verification

The distribution value a DER provides depends on whether it actually defers or avoids a capital investment, yet most programs anchor compensation to something other than a verified avoided cost. Illinois sets flat statutory rebate amounts, $300 per kilowatt of nameplate distributed generation, stepping to $250 after 2029, plus a performance-incentive floor of $10 per kilowatt of average dispatch. The legislation does not reference a marginal-cost nor an avoided-cost calculation, and it does not require utilities to verify that any deferral materializes. The statute directs the Illinois Commerce Commission to develop an annual compensation formula, not yet in place, intended to reflect avoided or deferred distribution capacity costs.[18] New York derives its Distribution Relief Value from each utility's marginal cost of service study, a territory-wide average, rather than from the avoided cost of a verified load reduction.[19] Connecticut sets Energy Storage Solutions incentives administratively, without a published avoided-cost basis for deferrable distribution upgrades.[20]

Design Approaches That Address This: Setting Incentives Based on Avoided Rather Than Marginal Costs

A different approach is visible in programs that tie compensation to estimated avoided costs. Colorado's Aggregator VPP program compensates on estimated avoided generation, transmission, and distribution costs, paying the distribution component as a location-specific adder to resources on constrained feeders; compensation is performance-based, a portion of the target capacity is procured competitively, and Year 2 value is indexed to market prices for automatic recalibration.[21]

The step these programs add is verification that the compensation produces a measurable change in load. A marginal cost study quantifies the cost of serving additional load across a service territory; it does not identify which investments DER can defer, in what quantity, or in which hours. Compensation calibrated to verified avoided costs, derived from measured load reductions, is a sound basis on which ratepayers can be assured that payments reflect value actually delivered rather than value theoretically available. Verification should also net out the dispatch that a resource's retail rate already covers: behind-the-meter storage on time-of-use or net-metering tariffs is already paid to shift load, crediting only the reduction beyond what those rates already cover.

Locational Targeting: System-Wide versus Feeder-Specific Value

The Problem: Universal Compensation Not Connected to Distribution Grid Needs

Distribution value is concentrated in a small number of feeders and substations with identified grid needs, yet most programs compensate uniformly across a service territory without requiring or rewarding siting at constrained locations. Illinois implements statewide, uniform rebates with no locational variation, so a battery on a constrained feeder receives the same compensation as one on a feeder with ample headroom.

Design Approaches That Address This: Constraint-Mapped Locational Bonuses and Feeder-Level Targeting

Programs that address this define a geographic perimeter tied to identified grid needs and offer higher incentives to resources within it. New York's VDER tariff structures its Locational System Relief Value as an incremental payment above the universal Distribution Relief Value, available only in designated substation areas where marginal cost analysis identifies above-average avoided distribution costs; each utility sets its own DRV and LSRV values and publishes a finite remaining-megawatt capacity for each qualifying location, so enrollment there is capped by that headroom (most zones were fully allocated by early 2024).[22] Colorado's Aggregator VPP pays a location-specific distribution capacity adder to resources on feeders or substation banks that its distribution system plan identifies as approaching their planning limit. Delaware's proposed Delmarva Locational Demand Response Pilot conditions bonus payments ($25 per year for bring-your-own-device and $100 per kilowatt up to $1,000 for bring-your-own-battery residential) on proximity to identified constrained feeders, layered on its base device programs.[23] Connecticut's December 2025 Energy Storage Solutions reform adds a higher enrollment incentive for residential systems at the grid edge. Maryland's Public Service Commission, implementing the DRIVE Act, has directed utilities to include locational value tied to distribution constraints, though the compensation structure is not yet final.[24] Nevada's proposed Grid Services riders pair an adjusted wholesale rate with a distribution capacity adder set to the marginal cost of distribution capacity; the adder is a system-wide default today, with a location-specific Distribution Node rate mechanism defined in the tariff but not yet populated.[25]

Locational differentiation does not require elaborate new technology or feeder-level metering at program enrollment: the Delaware, New York, and Nevada approaches all derive geographic eligibility from existing planning data. Defining a locational tier on top of a universal baseline, as New York has done, preserves broad program accessibility while concentrating the higher incentive where distribution costs can be avoided, making program costs proportionate to the grid value they are designed to capture.

Dispatch Windows: System Peak versus Local Distribution Peaks

The Problem: Wholesale-Market-Aligned Hours Misaligned to Feeder Constraints

The timing of a dispatch event determines whether a DER can provide grid services when a distribution grid need (constraint) is emerging. Most DER programs define dispatch windows by bulk-system peak periods or statutory time-of-use schedules that do not reliably coincide with the hours that drive distribution investment. Illinois embeds a 4 to 7 p.m. window in its statute, aligned with PJM summer peaks. New York establishes windows based on wholesale-market peak hours (a 4-hour window between 2 and 7 p.m. for most utilities). Connecticut uses ISO-NE system peak signals rather than identifying specific distribution feeder constraints. Each of these windows reflects a genuine bulk-system signal, but distribution feeder peaks frequently diverge from it.

Design Approaches That Address This: Dispatch Based on Local Rather Than System Conditions

Incorporating flexible event timing or removing seasonal constraints enables compensation for resources that reduce load at the specific times and locations where distribution grid needs arise. Colorado's Aggregator VPP program does not constrain events to fixed seasonal windows; summer-only resources may be called for up to 60 four-hour events per season, while year-round resources may be called for up to 80 four-hour events annually, with events callable at any time of day rather than limited to bulk-system peak hours. This flexibility enables utilities to adjust dispatch timing to match actual local grid needs rather than wholesale-market peak hours. Nevada's proposed GSR-E and GSR-C are event-based without fixed seasonal windows or prescribed dispatch hours.

Dispatch windows defined by local feeder conditions, or removed in favor of flexible event-based triggering, give utilities the operational control to call resources when and where distribution constraints occur. As electrification continues to reshape load profiles across the network, event-based dispatch structures will capture a growing share of distribution value that fixed bulk-system windows cannot reliably reach. A program architecture built around flexible event timing and customer-specific baseline measurement provides a sound basis for LVDER compensation tied to the distribution grid service value that DERs actually deliver.

Capacity Basis: Nameplate versus Effective Capacity

The Problem: Compensation for Installed Capacity Regardless of Demonstrated Performance

Most DER programs currently compensate based on installed or enrolled capacity rather than on demonstrated performance at specific times and locations that are driving grid needs. Illinois pays an upfront rebate based on nameplate capacity. Before April 2026, Connecticut paid enrollment incentives on installed capacity; the April 2026 reform shifted

toward performance-based compensation but does not explicitly condition payment on the effective feeder peak load reduction.

Design Approaches That Address This: Paying for Effective Peak Load Reductions Rather Than Nameplate Capacity

Colorado's Aggregator VPP compensates based on a baseline-versus-actual measurement of load reduction during called events, rather than installed capacity. Hawaiian Electric's Battery Bonus conditions monthly capacity payments on availability and dispatch during a defined peak window, while its BYOD and BYOD Plus programs pay credits tied to scheduled daily discharge rather than to installed kilowatt-hours.[26]

Performance-based payment, calibrated to measured load reduction during the critical hours that drive distribution investment, aligns LVDER compensation with the grid service actually delivered and gives participants a direct incentive to maintain availability when it matters most. This payment can be structured as a best-efforts approach that pays for the reduction a resource delivers during called events without obligating it to perform, or as a firm-capacity approach that requires an advance commitment to a specified reduction and penalizes non-performance. Only the firm structure gives distribution planners the certainty to defer a capital project, since a resource free to decline dispatch cannot be relied on to address a grid need. However, that firmness raises the participation bar and typically commands higher compensation. Programs built on that basis can scale with adoption and provide distribution planners the reliable, measurable performance commitment they need to treat DER as a credible alternative to capital investment. Without that firm DER program structure, the distribution grid infrastructure investment is not deferred or avoided, and those upgrades are now more costly after investing in DER programs that were unable to mitigate the grid need.

Commitment Terms: Fixed versus Adjustable

The Problem: Multi-Year Rate Locks That Prevent Recalibration as Grid Conditions Change

Revenue certainty has a legitimate place in DER program design and LVDER compensation. DER Aggregators financing hardware, aggregation platforms, or customer acquisition and deployment need a predictable revenue stream to recover that investment, and programs offering no assurance of future compensation will not attract the capital needed to build the fleet. Very long commitment terms extend beyond the horizon over which distribution grid needs and avoided costs can be reliably projected. New York locks DRV and LSRV rates for ten years at project qualification, and Connecticut requires a 10-year commitment period with no adjustment mechanism. Compensation is established when adoption is low and grid needs are clearly identified, and it remains fixed through years of rising penetration and shifting feeder conditions, decoupling payment from the avoided cost over time.

Design Approaches That Address This: Short-Term Pilots with Defined Scaling Pathways and Annual Adjustment Mechanisms

More recently developed programs have provided revenue certainty within shorter windows, preserving the ability to recalibrate. Rhode Island's Connected Solutions program locked participants who enrolled before June 2024 for five years, providing a defined revenue basis sufficient for equipment financing while creating a natural review point at renewal.[27] Hawaii's BYOD and BYOD Plus programs offer energy credits over a five-year term, with compensation conditions set at enrollment but limited to a horizon short enough for the utility to revisit rates as grid conditions evolve. Colorado's Renewable Battery Connect offers an upfront storage incentive of $250 per kilowatt. At the more flexible end of the spectrum, Nevada's proposed GSR-E and GSR-C specify no commitment term, with compensation recalibrated annually based on actual performance and grid conditions, maximizing adaptability while providing more limited revenue assurance for participants financing upfront investment. Maryland's PSC directives chart a middle path by limiting initial pilots to two years, with extensions possible, requiring a defined framework for transitioning to a permanent program so that early operating experience informs the longer-term compensation structure before rates harden.

The record of these programs suggests five years as a workable commitment horizon. One way to ground that horizon is a target payback period, the time a typical installation needs to recover its upfront cost, which ties the term to customer economics and to the level of compensation offered. This window is long enough to support equipment financing and customer acquisition, but short enough to revisit dispatch requirements, enrollment caps, and compensation rates before conditions change substantially. A term structured around that horizon provides both developers and utilities with a basis for planning while preserving the flexibility to recalibrate as the fleet grows and distribution needs evolve.

The five-year term also aligns with distribution infrastructure deferral, in which a distribution infrastructure project can take three to five years to progress from an identified grid need to installed and operational (“used and useful”) equipment. Similarly, a DER program to mitigate distribution grid needs will take time to develop, with a timeframe depending on the amount of DER already interconnected at that distribution feeder and on utility/aggregator operational systems to manage the DER and provide grid services when and where needed.

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[25] NC Clean Energy Technology Center, *50 States of Virtual Power Plants and Supporting Distributed Energy Resources: 2025 State Policy Snapshot* (Raleigh: NCCETC, January 2026), 39-40 (Nevada GSR-E and GSR-C, PUCN Dockets 25-10012 and 25-10013, proposed October 2025).

[26] Hawaiian Electric Company, *Battery Bonus Program* (Honolulu: HECO, 2021); Hawaiian Electric Company, *Rule No. 33: Bring Your Own Device (BYOD) Program* (Honolulu: HECO, April 2024).

[27] NC Clean Energy Technology Center, *50 States of Virtual Power Plants and Supporting Distributed Energy Resources: 2025 State Policy Snapshot* (Raleigh: NCCETC, January 2026), 48-50.