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Track 2 Workshop Report: Distribution System Operator DER Orchestration

HIGH DISTRIBUTED ENERGY RESOURCES PROCEEDING (R.21-06-017)

ENERGY DIVISION STAFF

Energy Division Workshop Report: DSO-led DER Orchestration
High DER Track 2 (R.21-06-017)
Workshop Date: May 21, 2026

I. Background

The California Public Utilities Commission (CPUC) initiated the High Distributed Energy Resources (DER) Proceeding (R.21-06-017) in 2021 to examine how California's electric distribution system should evolve to accommodate a High Distributed Energy Resources (High DER) future. The proceeding is organized into three tracks addressing distribution planning and execution, operational needs, and smart inverter operationalization and grid modernization.

In August 2023, the Commission issued an Amended Scoping Memo that directed Track 2 to examine the operational needs required to efficiently manage a high-DER distribution system while enabling DERs to provide grid services, reducing ratepayer costs, increasing equity, and supporting reliability and state policy objectives. Track 2 also aims to identify the gaps and barriers within the current utility-operated distribution system that require further development.

In 2024, the Commission retained Gridworks to facilitate a three-part Future Grid Study (FGS) workshop series. Through these workshops, stakeholders identified key operational needs for a high-DER future, assessed gaps between current utility capabilities and future operational requirements, and discussed potential solutions. The resulting FGS Report identified gaps between current distribution system operational capabilities and future operational needs and proposed a set of recommendations to address those gaps. These recommendations helped establish the foundational elements of the DER orchestration framework currently being developed under Track 2.

The Assigned Commissioner's Ruling (ACR), issued on March 23, 2026, focused the next phase of Track 2 on the development of a DER orchestration framework for utility distribution system operators (DSOs).

II. Introduction

As directed in the March 23 ACR, Energy Division convened the first of two DER orchestration workshops on May 21, 2026. The workshop was intended to provide a forum for stakeholders to discuss the foundational elements necessary to support a utility-led DER orchestration framework, including associated implementation challenges, operational requirements, and governance considerations. Consistent with the Assigned Commissioner's direction, the workshop also sought stakeholder input on the potential application process for DER orchestration, including guiding principles, technical requirements, and other foundational framework elements.

The workshop was designed to identify areas of stakeholder alignment, highlight issues requiring further development, and inform the Commission's consideration of future utility-specific DER orchestration proposals. Participants also discussed topics that may inform future applications, including cost recovery, implementation approaches, scalability, and the potential need for additional workshops or stakeholder processes.

III. Purpose and Scope of the Workshop

Three primary objectives guided the workshop discussions. First, to support development of a potential application framework for DSO-led DER orchestration and facilitate early engagement among investor-owned utilities and stakeholders regarding the structure and content of future utility applications. Second, the workshop was intended to assess the foundational capabilities, technologies, and operational requirements necessary to support DER orchestration, while identifying key issues, gaps, and areas requiring additional analysis or policy development. Finally, the workshop provided an opportunity to discuss potential next steps in the proceeding, including whether additional workshops, working groups, pilot programs, or other stakeholder processes may be necessary to support further development of a DER orchestration framework.

To facilitate these discussions, the workshop was organized around six key topic areas that were derived from Questions 1 through 17 of the (ACR) for Track 2 issued on March 23, 2026:

1. Grid Services and Use Cases Enabled by DSO-led DER Orchestration
2. Open, Interoperable Communications for DER Visibility and Behind-the-Meter DER Grid Services
3. Dispatch Mechanisms and Aggregator Roles
4. Cost-Benefit Methodologies and Valuation Frameworks
5. Incentive Structures and Mechanisms
6. Evaluating IOU Readiness and Scalability of Rollouts

IV. Summary of Party Perspectives by Key Topic

This report summarizes the perspectives, proposals, and discussion points raised by parties during the workshop and organizes those discussions according to the six key topic areas identified in the previous section. The depth and scope of responses varied by party.

The ten parties who presented at the workshop are: Pacific Gas & Electric (PG&E), Southern California Edison (SCE), San Diego Gas & Electric (SDG&E), California Community Choice Association (Cal CCA), Public Advocates Office (Cal Advocates), Environmental Defense Fund (EDF), Universal Devices, Utility Consumers Action Network (UCAN), Clean Coalition, and CAISO.

The summaries provided in this report contain footnotes with slide numbers referring to information in party slides. Party slides can be found in the final workshop slide deck in Appendix B.

1. Grid Services and Use-Cases Enabled by DSO-led DER Orchestration

This topic focused on identifying and defining the distribution-level grid services that could be provided through DER orchestration. Stakeholders were asked to discuss how orchestrated DERs could support reliability, outage avoidance, infrastructure deferral, electrification, and other operational objectives. Participants were also asked to provide examples of specific use cases that demonstrate how coordinated DER dispatch could address distribution system needs and create value for customers and ratepayers.

Pacific Gas & Electric

PG&E framed DER orchestration as a core component of its future DSO model, where aggregated DERs and flexible loads are coordinated through a Virtual Power Plant (VPP) structure to provide services across transmission and distribution systems. PG&E argued that the value of orchestration lies in using DERs as planning-grade resources that can provide reliable, dispatchable, and measurable grid services.

PG&E focused on three use cases where flexibility is likely to be less expensive than traditional utility investments:

1. System peak reduction, where DERs provide firm and reliable capacity at lower cost than supply-side alternatives
2. Speed-to-power applications, where load management and DER flexibility allow new loads and electrification projects to be energized more quickly within existing grid constraints
3. Resource-efficient grid investments, where flexibility can be incorporated into planning processes to reduce or defer distribution and transmission upgrades.

PG&E emphasized that resources should be dispatchable, verifiable, locationally relevant, and dependable enough for planning and operational decisions.[1]

Southern California Edison

SCE defined DER orchestration as the coordinated management of DERs by a distribution system operator using forecasting, real-time data, and control signals to address location- and time-specific grid needs. SCE presented a broad range of use cases, including:

- optimizing EV charging to reduce circuit peaks
- lowering circuit loading to increase operational flexibility
- coordinating DER portfolios to reduce procurement costs
- enabling flexible service connections
- helping customers avoid service panel upgrades

SCE distinguished orchestration from demand response and dynamic rates, emphasizing that direct control of DERs can deliver unique distribution-level benefits such as deferring infrastructure investments, supporting speed-to-power objectives, mitigating local constraints and secondary peaks, and potentially providing outage support. Overall, SCE viewed orchestration as a reliable and continuous source of load flexibility that can be integrated into distribution planning and operations.[2]

San Diego Gas & Electric

SDG&E took an implementation-focused approach to DER orchestration, emphasizing specific distribution services rather than a broad vision of grid transformation. Possible use cases included:

- real-time thermal overload mitigation
- voltage support
- distribution upgrade deferral
- abnormal-condition support
- speed-to-power applications
- charging management
- vehicle-to-grid services

SDG&E noted that many of these applications remain unproven at scale, specifically noting challenges related to device capabilities, aggregator readiness, cost-effectiveness, and operational complexity.[3]

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[1] High DER Track 2 DER Orchestration Workshop Materials Slide 32
[2] High DER Track 2 DER Orchestration Workshop Materials Slides 42-44
[3] High DER Track 2 DER Orchestration Workshop Materials Slides 61-62

Public Advocates Office

Cal Advocates articulates high-level goals of DER orchestration: using existing grid capacity more efficiently, avoiding or deferring upgrades where cost-effective, supporting electrification and faster energization, improving reliability and operational flexibility, and reducing ratepayer costs. Cal Advocates does not enumerate specific use cases, arguing instead[4] that existing pilots such as managed charging, battery controls, aggregated DERs, local orchestration, and Flex Connect should inform use case development through a structured working group process rather than being defined prematurely.

Environmental Defense Fund

EDF frames DER orchestration through the lens of export tariffs and a bidirectional ratemaking structure. In their presentation[5], EDF references a PNNL (2023) grid services definitions report to present a structured list of services, including peak load shaving, voltage support, frequency regulation, load shaping, spin/non-spin reserve, and emergency power, arguing that common terms and definitions are a prerequisite for standardization at the grid edge and, by extension, for DSO-led orchestration.

Utility Consumers Action Network

UCAN stated that the primary goal of DER orchestration should ultimately be to minimize total system costs for ratepayers.[6] They believe this is achievable through using grid orchestration as a capital expenditure avoidance tool where upgrades can be deferred through a coordinated DER marketplace.

Clean Coalition

Clean Coalition outlined two overall use cases for DER grid orchestration. First, essential grid services and aiding grid reliability through energy balancing, voltage balancing, and frequency balancing.[7] Second, saving costs for ratepayers. This is achievable by avoiding costly transmission fees and upgrades through strengthening the distribution system, and by maximizing utilization of existing distribution grid assets further avoiding costly upgrades.[8] Clean Coalition closed with a list of grid services broken into two categories:

1. Customer Energy Services:
    - Backup Power
    - Increased PV Self-Consumption

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[4] High DER Track 2 DER Orchestration Workshop Materials Slide 85
[5] High DER Track 2 DER Orchestration Workshop Materials Slide 142
[6] High DER Track 2 DER Orchestration Workshop Materials Slide 105
[7] High DER Track 2 DER Orchestration Workshop Materials Slide113
[8] High DER Track 2 DER Orchestration Workshop Materials Slide 114-117

- Demand Charge Mitigation
- Time Shifting Charge
- TOU Optimization
- Energy Arbitrage

2. Operational Grid Services:
    - Peak Load Shaving
    - Voltage Support
    - Frequency Regulation
    - Load Shaping
    - Spin/Non-spin Reserves
    - Emergency Power[9]

Universal Devices

Universal Devices discussed behind-the-meter residential devices (thermostats, EV chargers, pool pumps, water heaters) that are already installed and argue that they are capable of providing flexibility within a DSO orchestration framework. They believe that if these devices are not included, grid cost reduction will be limited to 7-10%, when including residential devices could potentially deliver significantly higher savings.

Universal Devices also stated that the framework is fragile because it depends entirely on one signal type. If that signal type changes (e.g., from VOE to something else), the entire framework would need to be rebuilt. Additionally, manufacturers have not been given clear direction to support the standards being discussed.

California Community Choice Association

CalCCA highlighted the growing role of Community Choice Aggregators in developing and deploying innovative DER programs, arguing that CCAs are increasingly capable of delivering flexibility services and responding to local grid needs while maintaining strong customer relationships and community-centered program design. Rather than focusing on a particular set of utility-defined use cases, CalCCA emphasized that the orchestration framework should be designed to maximize participation from a broad set of market actors including CCAs, aggregators, and DER providers, so that cost-effective flexibility solutions can emerge.[10]

2. Advance Open, Interoperable Communication for DSO DER Visibility and Behind-the-Meter DER Grid Services

[9] High DER Track 2 DER Orchestration Workshop Materials Slide 125
[10] High DER Track 2 DER Orchestration Workshop Materials Slides 93 and 98

This topic examined the communications, visibility, and data requirements necessary to support DER orchestration. Stakeholders were asked to discuss the level of DER visibility required for dispatch and control, the role of ADMS and DERMS platforms, and how technologies such as AMI 2.0 could enhance system awareness and operational capabilities. Discussion also included communications protocols, interoperability standards, data-sharing frameworks, privacy and cybersecurity protections, and considerations regarding ownership of customer-side and utility-side technologies.

Pacific Gas & Electric

PG&E emphasized the importance of a utility-integrated DERMS platform that provides visibility into DER performance, forecasting, dispatch, measurement, and verification. PG&E envisions DERMS serving as the central coordination layer between DERs, aggregators, wholesale markets, and utility operations systems with integration into ADMS, SCADA, planning tools, and customer data systems. PG&E supports standard communications through protocols such as IEEE 2030.5, OpenADR, OCPP, and APIs, and emphasized the need for interoperable technology, telemetry, and data-sharing frameworks to increase participation. PG&E also highlighted the need to balance increased DER visibility with cybersecurity protections and appropriate limits on locational data.[11]

Southern California Edison

SCE proposed an overall DER orchestration architecture in which ADMS, DERMS, aggregators, OEM platforms, customer devices, and AMI 2.0 work together to support orchestration. SCE views DERMS as responsible for communicating distribution-level operating constraints while third-party platforms translate those requirements into device-level actions. SCE highlighted IEEE 2030.5 as a communication pathway and noted that protocol translation layers could accommodate OpenADR, OCPP, and device-specific APIs. AMI 2.0 was identified as an important future capability that could improve visibility, customer usage disaggregation, communications, and optimization. Overall, SCE stressed that orchestration would require granular, near-real-time visibility into DER operations providers.[12]

San Diego Gas & Electric

SDG&E advocated for a "fit-for-purpose" approach to DER visibility, arguing that visibility requirements should depend on the specific grid service being provided rather than adopting a universal standard. They identified several possible visibility pathways,

[11] High DER Track 2 DER Orchestration Workshop Materials Slide 33
[12] High DER Track 2 DER Orchestration Workshop Materials Slide 47

including aggregator-level monitoring, direct device communications for utility-dispatched resources, and customer meter-level views that reflect net grid impacts. SDG&E emphasized feeder forecasting, real-time telemetry, and DER registries as important capabilities while noting that AMI 2.0 could enhance future visibility and validation. SDG&E opposed mandating any specific communications protocol, instead prioritizing interoperability, open access, privacy protections, cybersecurity requirements, and clear ownership boundaries between utility-operated and customer-owned technologies.[13]

California Community Choice Association

CalCCA focused primarily on concerns that utility-centric communication architectures could limit market participation and innovation. They argued that enterprise ADMS and DERMS platforms were originally designed for utility operations rather than market administration and may not scale effectively to support large numbers of third-party DERs. CalCCA also expressed concern that reliance on IEEE 2030.5 could increase participation costs and create barriers for aggregators. Instead, they suggested that market-oriented protocols such as OpenADR 3.0 may be better suited for flexibility markets because they are designed around portfolio-level coordination, interoperability, and broad participation by DER providers.[14]

Utility Consumers Action Network

UCAN stated that a marketplace with co-equal aggregator participation would require both protocol neutrality and common open-access platforms to support engagement. UCAN supported open communication standards such as OpenADR alongside IEEE 2030.5 and cautioned that mandating any single protocol would lead to OEM costs and bottlenecks.[15] UCAN also stated that common platforms, such a DER Registry for visibility, a Data Hub for multi-entity data exchange via API, and a Flexibility Market Platform for transparent procurement of services are all essential for an equal opportunity marketplace. A statewide DER registry is needed to provide proper visibility to DSO, TSO, and aggregators. A statewide Datahub would serve as a means to monitor customer usage data. Finally, a Market Platform would serve as the means for the DSO to contract out load flexibility or other services to the aggregators.[16]

Clean Coalition

[13] High DER Track 2 DER Orchestration Workshop Materials Slides 64-64
[14] High DER Track 2 DER Orchestration Workshop Materials Slides 99-100
[15] High DER Track 2 DER Orchestration Workshop Materials Slide 106
[16] High DER Track 2 DER Orchestration Workshop Materials Slide 107

Clean Coalition advocated for a system in which the DSO operates grid-level DERMS and coordinates with third-party and CCA-operated edge DERMS through an interoperable interface.[17]

Environmental Defense Fund

Although EDF does not explicitly address communications architecture or interoperability standards, the :Grid Services Framework" referenced in slide 16 of their presentation implicitly requires interoperable communications to operationalize services such as frequency response and voltage management, but this party does not develop this point directly.

Public Advocates Office

Cal Advocates identifies "comms /technology /data access" as a key open question that pilots should help answer[18] but does not propose specific interoperability standards or communications protocols. Cal Advocates treats this as an unresolved issue to be addressed within a working group process.

Universal Devices

Universal Devices identified what they believe are four communication gaps:

1. Standards are not ready for implementation: IEEE 2030.5 is referenced throughout the proceeding but lacks specific technical details needed to build systems. Matter, a connectivity standard meant to be used to connect devices between different manufacturers, was added for EV chargers. However, as of October 2025 only one certified product exists. Matter for battery storage has zero production devices available.
2. Millions of legacy devices face hurdles to engaging in the framework: Devices already installed using Z-Wave, ZigBee, Modbus, and other protocols have no pathway to connect to DSO orchestration.
3. The framework cannot adapt to policy changes: If the signal type changes in the future, the entire system could break and would need to be rebuilt.
4. Manufacturers are confused about direction: Current approach assumes manufacturers will switch to new standards, but some vendors are already using non-standard variations (like SCE's Australian CSIP variant) because the standard doesn't have required features.

3. Dispatch Mechanisms and Aggregator Roles

[17] High DER Track 2 DER Orchestration Workshop Materials Slide 118
[18] High DER Track 2 DER Orchestration Workshop Materials Slide 85

This topic focused on the roles and responsibilities of utilities, third-party aggregators, CCAs, and customers within a DSO-led orchestration framework. Stakeholders were asked to discuss potential dispatch structures, including Dynamic Operating Envelope (DOE)-based approaches and contractual arrangements, as well as how customer participation, open access, oversight, and independent monitoring could be incorporated into future orchestration programs.

Pacific Gas & Electric

PG&E proposed a DSO-led orchestration model in which the utility identifies grid needs and translates those needs into dynamic operating envelopes that guide DER dispatch. Under this framework, customers continue to interact with trusted third-party partners and aggregators, while PG&E retains responsibility for reliability, planning, measurement, and operational guardrails. PG&E envisions a competitive marketplace where DERs and third party aggregators compete to satisfy grid needs, with compensation tied to delivered grid value, arguing that this structure balances customer simplicity and utility accountability.[19]

Southern California Edison

SCE envisions a model where DER orchestration may occur either directly through the utility or through aggregators that manage customer devices and optimize resource portfolios. Aggregators would play a significant role in customer engagement, enrollment, device integration, and dispatch execution. SCE's proposed architecture relies on DERMS communicating distribution constraints while third-party systems translate those requirements into customer-level actions.[20]

San Diego Gas and Electric

SDG&E provided a clear delineation of developing stakeholder responsibilities. IOUs/DSOs would identify grid needs, establish procurement structures, and verify performance, while aggregators would manage DER portfolios, enroll customers, commit resources, and assume performance obligations. Customers could participate directly or through aggregators and CCAs. SDG&E emphasized open access and transparent procurement, arguing that any qualified provider should be able to compete.[21]

California Community Choice Association

Cal-CCA encouraged consideration of independent marketplace operators and other governance models that could promote transparency, competition, and broad market

[19] High DER Track 2 DER Orchestration Workshop Materials Slide 27
[20] High DER Track 2 DER Orchestration Workshop Materials Slide 44
[21] High DER Track 2 DER Orchestration Workshop Materials Slide 67

participation. Cal-CCA suggested that lessons from wholesale market independence and emerging flexibility markets should inform California's approach before assigning dispatch authority exclusively to utilities.[22]

Universal Devices

Universal Devices separated the problem into two layers: the aggregation layer (who manages the fleet) and the device execution layer (how signals get translated into device commands). Universal Devices does not dispute that aggregators can manage fleets well. They argue that the missing piece is that once an aggregator sends a signal to hundreds of different devices in a customer's home, someone must translate that one signal into the specific command each device understands (Modbus, Z-Wave, Matter, etc.).

Universal Devices proposed that different models can coexist – utility direct, aggregator-managed, or CCA-managed – as long as there is a platform layer handling device execution. This way, aggregators compete on value-added services (optimization algorithms, forecasting) rather than on device integration, which creates barriers to entry.

Clean Coalition

Clean Coalition showed support for DSOs using a transparent marketplace and acquiring grid services through third party aggregators controlling DERs and other BTM resources.[23]

Utility Consumers Action Network

UCAN included VPPs, CCAs, ESPs, and third-party DER providers as aggregators in a DER orchestration marketplace. UCAN framed these aggregators as the direct controllers of devices enrolled in their programs, and which respond to marketplace signals.[24]

4. Cost-Benefit Methodologies and Valuation Frameworks

This topic explored approaches for quantifying the value of DER orchestration and evaluating its benefits relative to traditional utility investments. Stakeholders were asked to discuss valuation methodologies that could capture distribution-level benefits, optimize existing grid capacity, and measure the net value of orchestration to ratepayers. Participants were also asked to identify cost-benefit frameworks that could be used to compare DER orchestration solutions against conventional infrastructure alternatives.

Pacific Gas & Electric (PG&E)

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[22] High DER Track 2 DER Orchestration Workshop Materials Slide 101-103

[23]

[24] High DER Track 2 DER Orchestration Workshop Materials Slide 105

PG&E proposed three distinct flexibility models:

1. value-exchange services where flexibility is embedded in a utility offering
2. competitively procured flexibility acquired through market mechanisms
3. customer-funded flexibility where customers pay for accelerated service

PG&E argued that compensation should be linked to delivered grid value and affordability outcomes and they expressed skepticism toward compensation structures that create profit centers without reducing overall customer costs. PG&E emphasized that flexibility programs should produce net savings for ratepayers.[25]

Southern California Edison (SCE)

SCE viewed incentive design as an area requiring further pilot testing and program development. They identified compensation structures, customer participation models, and third-party partnership arrangements as key areas where additional learning is needed before large-scale deployment. Existing dynamic rate, EV, and demand response programs were presented as useful foundations that could inform future orchestration incentives and customer compensation approaches. [26]

San Diego Gas and Electric (SDG&E)

SDG&E did not endorse shared savings mechanisms at this stage, suggesting that shared savings designs raise broader ratemaking issues that may be better addressed in a separate proceeding. SDG&E also distinguished DER orchestration from real-time pricing, arguing that orchestration is based on utility-directed dispatch while real-time pricing relies on voluntary customer responses to price signals. [27]

Public Advocates Office

Cal Advocates explicitly identifies a cost-benefit framework as the first foundational issue to resolve, describing it as an approach to determining whether DER orchestration creates net ratepayer value. Cal Advocates does not propose a specific methodology but insists one must be established before any scaling decisions are made.

Clean Coalition

Clean Coalition emphasized the need to emphasize local value, urging DSOs to work with DER owners to produce value stacks maximizing ratepayer benefits. Clean Coalition

[25] High DER Track 2 DER Orchestration Workshop Materials Slide 28
[26] High DER Track 2 DER Orchestration Workshop Materials Slides 51-52
[27] High DER Track 2 DER Orchestration Workshop Materials Slide 71

acknowledged frameworks such as the Locational Net Benefit Analysis (LNBA) but believe a new framework will need to be designed. [28]

Environmental Defense Fund

EDF does not propose a stand-alone cost-benefit methodology. EDF implicitly supports applying traditional cost-of-service ratemaking principles bidirectionally (to both import and export), arguing that doing so would more equitably allocate costs to exporting facilities and better align costs and revenues over time, yielding greater rate stability.

5. Incentive Structures and Mechanisms

This topic examined potential compensation and incentive structures that could encourage participation in DER orchestration programs while maintaining alignment with ratepayer interests. Stakeholders were asked to discuss compatibility with real-time pricing, lessons learned from incentive structures adopted in other jurisdictions, and the potential use of shared savings mechanisms or other compensation approaches to support DER participation.

Pacific Gas & Electric

PG&E framed affordability as the primary objective of DER orchestration and argued that flexibility solutions should only be pursued when they provide measurable cost savings relative to traditional infrastructure investments. They advocated for planning-grade DERs that can compete directly with wires solutions and emphasized compensation structures tied to demonstrated grid value. PG&E emphasized that their framework is centered on ensuring that orchestration lowers costs for all customers rather than creating standalone revenue opportunities for technology providers. [29]

Southern California Edison

SCE emphasized that much of DER orchestration's value comes from maximizing utilization of existing infrastructure, accelerating customer energization, reducing procurement costs, and deferring future investments. They argued that orchestration must be integrated into planning processes to fully capture these benefits. SCE views asset deferral, speed-to-power benefits, operational flexibility, and affordability improvements as the primary sources of value that should be reflected in future cost-benefit analyses.

San Diego Gas and Electric

[28] High DER Track 2 DER Orchestration Workshop Materials Slide 119
[29] High DER Track 2 DER Orchestration Workshop Materials Slide 34

SDG&E recommended using the California Standard Practice Manual as a foundation while incorporating distribution-specific considerations. These include locational and temporal avoided costs, comparison against conventional utility solutions, full accounting of program costs, telemetry and settlement costs, measurement and verification expenses, and bill impacts. SDG&E also emphasized compensation discipline, arguing that payments should be tied to demonstrated needs and ratepayer benefits rather than broad assumptions about future DER value.[30]

Environmental Defense Fund

The following is the central focus of EDF's position, which forms three distinct arguments:

1. Export tariffs as price signals[31]: EDF proposes that export tariffs create bidirectional price signals, rewarding export during peak periods (e.g., a credit of 25.37 c/kWh during 2–8 pm) and charging for export during solar soak periods (1.85 c/kWh), incentivizing DERs to shift export timing in ways that benefit the grid.
2. Utility incentive alignment[32]: EDF argues that export tariffs give utilities a return on rate-based investments to expand hosting capacity, generate recurring revenue from exporters, and subject utility system plans to prudency review, aligning utility financial incentives with DER scaling goals.
3. Flexible interconnection incentives[33]: EDF argues that export tariff price signals can incentivize flexible, non-firm connections, enabling greater grid utilization without requiring costly upfront infrastructure upgrades.

Public Advocates Office

Cal Advocates addresses incentives and cost recovery incentives at a framework level rather than proposing specific mechanisms. Cal Advocates flags that IOUs may have already recovered some DER orchestration costs through GRC modernization components[34] and argues that the incentive and cost recovery framework must be established (and existing cost recovery reviewed) before new IOUs applications are considered.

6. Evaluating IOU Readiness and Scalability of Rollouts

This topic focused on implementation readiness and long-term scalability. Stakeholders were asked to discuss how future applications could demonstrate utility readiness,

[30] High DER Track 2 DER Orchestration Workshop Materials Slide 69
[31] High DER Track 2 DER Orchestration Workshop Materials Slide 132-134
[32] High DER Track 2 DER Orchestration Workshop Materials Slide 137
[33] High DER Track 2 DER Orchestration Workshop Materials Slides 138-139
[34] High DER Track 2 DER Orchestration Workshop Materials Slide 84

including the maturity of ADMS and DERMS platforms, dispatch capabilities, operational metrics, and organizational preparedness. Participants were also asked to address the role of Electrification Impact Study (EIS) 2.0 findings, potential pilot programs, rollout pathways, and how the Commission should account for differing levels of readiness across the investor-owned utilities.

Pacific Gas and Electric

PG&E argued that California should move away from fragmented demand flexibility programs and toward a unified orchestration framework built around DER visibility, DERMS functionality, flexible interconnection services, and competitive procurement. PG&E believes they are well positioned to serve as the DSO because of their responsibility for safety, reliability, and grid planning. They envisioned having a 'sandbox' phase for initial implementation to maximize learning opportunities and inform future piloting and rollout plans. PG&E's vision assumes increasing integration of DER visibility and flexibility into planning and operational processes so that flexibility can compete directly with traditional infrastructure upgrade solutions.[35]

Southern California Edison

In their presentation SCE presented an implementation roadmap for DER Orchestration. They proposed a phased approach beginning with pilots and studies, followed by maturation of ADMS, DERMS, customer engagement capabilities, and AMI 2.0 deployment. SCE envisions orchestration becoming progressively integrated into planning processes between 2026 and 2033, with successful pilot programs ultimately scaling into broader operational programs. They emphasized that customer participation, multi-device integration, compensation models, and planning methodologies all require additional development before orchestration can be deployed at scale.[36]

San Diego Gas and Electric

SDG&E advocated a framework-first approach that begins with establishing principles around safety, interoperability, cybersecurity, and cost recovery. They proposed staged progression from framework development to capability buildout, targeted pilots, readiness-driven applications, and eventually scaled deployment. SDG&E opposed mandated implementation timelines and argued that utilities should proceed only when operational capabilities, DERMS functionality, and demonstrated ratepayer benefits justify broader deployment.[37]

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[35] High DER Track 2 DER Orchestration Workshop Materials Slide 36-37
[36] High DER Track 2 DER Orchestration Workshop Materials Slides 47-48
[37] High DER Track 2 DER Orchestration Workshop Materials Slides 73-75

Utility Consumers Action Network

UCAN advocated for an accelerated rollout of a demand flexibility marketplace, starting now and going live in the next fifteen to eighteen months. UCAN's proposed process is broken into five steps[38]

1. RFI and Working Group: Over Months 0-3 the CPUC would send out an RFI for platform scope and integration architecture as well as establish a working group with parties
2. Proposal, Comment, and Order: Over Months 4-6 ED proposal goes on the record for comment
3. Competitive Procurement: Over Months 7-9 ED or other designer sends out RFP for platform(s)
4. Integration and Registration: Over Months 9-15 selected Vendor(s) begin integration and early registration
5. Go Live: Over Months 15-18 ongoing procurement cycles, evaluation metrics inform next cycle

Universal Devices

Universal Devices indicated concern that without a Commission-level framework for device-level orchestration, each IOU will build proprietary systems. This could create a problem where manufacturers and aggregators must integrate three different times, and customers moving between utility territories find systems may not work together, which could create a major barrier to scaling.

Public Advocates Office

Cal Advocates addresses the following points directly as central to their overall position:

1. Cal Advocates argues that IOU applications are premature because foundational framework issues remain unresolved, noting that even the IOUs' own comments suggest it is too early to file applications, and that cost recovery should run through GRCs rather than a new application process.

2. Cal Advocates identifies performance and evaluation metrics defining what IOUs must demonstrate before scaling, and accountability and oversight rules as prerequisites that must be established first.

3. Cal Advocates proposes building the readiness evaluation from work already underway, mapping GRC/Grid Modernization activities to readiness questions around existing capabilities, target locations, incremental costs, and expected

[38] High DER Track 2 DER Orchestration Workshop Materials Slides 106-107

benefits, and drawing on pilot learnings around upgrade deferral potential, customer participation, and control performance.

4. Cal Advocates proposes a specific process timeline where a decision to adopt a framework related to TSO-DSO coordination would previously include a Working Group, with reports and party comments included as part of framework development before officially adopting a framework.

V. Conclusion

Workshop discussions highlighted the broad agreement that DER orchestration has the potential to become an important operational capability for managing California's increasingly distributed and electrified grid. Participants identified DER visibility, interoperability, communications infrastructure, and data access as foundational requirements for any future orchestration framework. Stakeholders also emphasized the need for clear valuation methodologies, cost-benefit frameworks, performance metrics, and compensation structures to ensure that DER orchestration delivers measurable ratepayer value. Many parties further highlighted the importance of pilot programs, demonstrations, and phased implementation strategies to test operational concepts, evaluate customer participation, and inform future deployment decisions.

Participants generally agreed that DER orchestration could enable a range of distribution-level services, including infrastructure deferral, reliability support, load management, and speed-to-power solutions that accelerate customer energization while making more efficient use of existing grid infrastructure. Stakeholders also recognized that achieving these outcomes will require improved DER visibility, interoperable communications and data-sharing frameworks, enhanced dispatch and control capabilities, and greater coordination among utilities, aggregators, customers, Community Choice Aggregators (CCAs), and other market participants.

At the same time, the workshop revealed differences in stakeholder perspectives regarding the appropriate structure, implementation pathway, and level of utility involvement in DER orchestration. Investor-owned utilities and some other stakeholders generally supported a utility-led DSO model, emphasizing the need to maintain responsibility for safety, reliability, and grid planning while leveraging DER flexibility to address distribution system needs. Other stakeholders expressed concerns regarding market structure, competition, and potential conflicts of interest, advocating for greater consideration of independent marketplace operators, open-access platforms, and alternative governance approaches.

The workshop reflected broad support for continued exploration of DER orchestration as a tool to improve grid flexibility, affordability, and reliability while enabling greater utilization of distributed energy resources. The workshop also demonstrated that important policy, technical, operational, and market design questions remain unresolved and will require additional stakeholder engagement.

Appendix A – Workshop Agenda

Time	Party/Agenda Item
10:00am-10:15am *(15 min)*	**CPUC:** Introduction, Safety, Logistics, Opening Remarks
10:15am-10:45am *(30 min)*	**ED:** Background, Workshop Objectives, Framing, and Key Discussion Topics
10:45am-11:45am *(1hr)*	**PG&E**: Address Key Topics + Q&A
11:45am-12:45pm *(1hr)*	Lunch
12:45pm-1:45pm *(1hr)*	**SCE:** Address Key Topics + Q&A
1:45pm-2:45pm *(1hr)*	**SDG&E:** Address Key Topics + Q&A
2:45pm-3:00pm *(15 min)*	Break
3:00pm-4:55pm *(115 min)*	**Other Party Presentations: (1)** Cal Advocates **(2)** CalCCA **(3)** UCAN **(4)** Clean Coalition **(5)** EDF **(6)** Universal Devices and **(7)** CAISO *(~15-20 min per party including Q&A)*
4:55pm-5:00pm *(5 min)*	**CPUC:** Wrap-up and Next Steps

Appendix B – Workshop Slides

Distributed Energy Resources (DER) Orchestration Framework Development Workshop

High DER Proceeding (R.21-06-017) Track II

Workshop #1

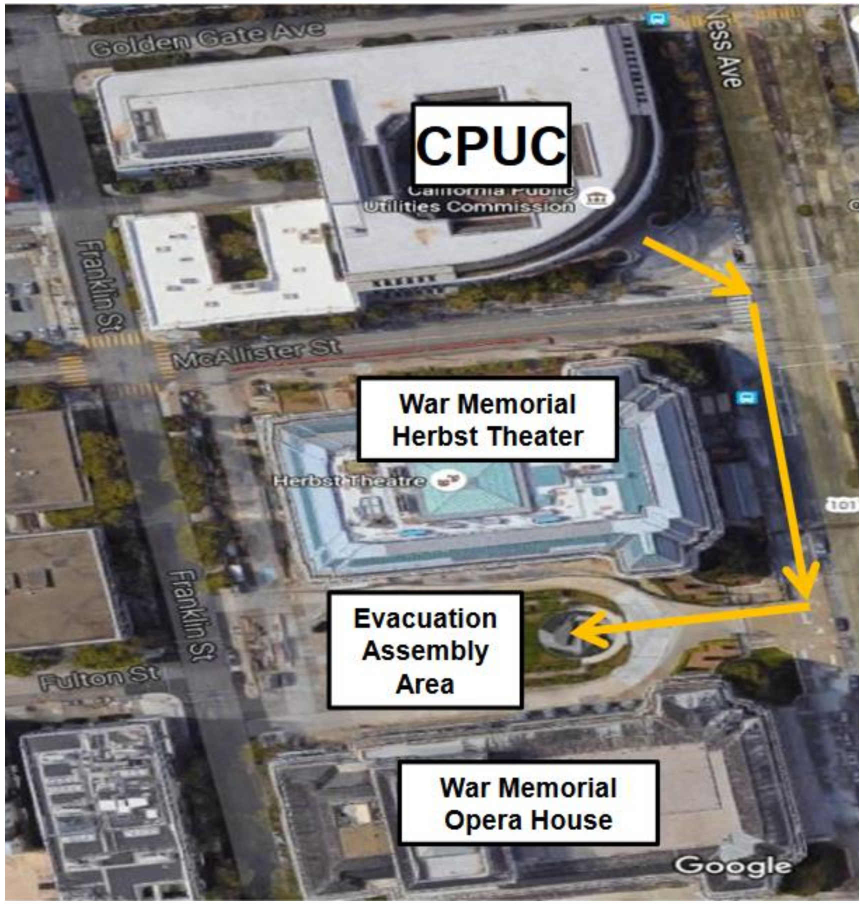
CPUC Energy Division

May 21st, 2026

California Public Utilities Commission

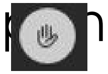
Safety Announcements

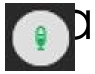
- **In case of an emergency:**
  - CPUC Staff will call 911
  - To evacuate, proceed out of 1 of 2 exits to Civic Center Plaza
    - Exit toward Van Ness / McAllister
    - Walk past City Hall
- **Bathrooms & water fountain across the lobby**



Ground Rules & Workshop Logistics

- **Ground Rules:**
  - Raise your hand for questions, both in the room and online
  - Identify yourself and your organization before speaking (include your org name on Webex icon)
  - Try not to repeat points that have already been made, and stay on topic
  - Please do not interrupt speakers and be respectful of open dialogue
- **Workshop Logistics**:
  - Workshop is being recorded and a link to the recording will be distributed to the service list
  - WebEx and phone participants are muted until called on. Please remember to mute yourself when finished speaking.
  - Webex participants may type questions/comments in the 'chat' to be read aloud during Q&A.
    - When your question is addressed you may raise your hand to ask yourself and/or follow up for clarification.





Opening Remarks

Commissioner Darcie L. Houck, Pres. John Reynolds,
ALJ Chang

Agenda

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4:55pm-5:00pm *(5 min)*	**CPUC:** Wrap-up and Next Steps

Background & Framing

Energy Division Staff

Background & Procedural History

The CPUC's High DER Proceeding (R.21-06-017) aims to modernize California's electric distribution grid and planning processes so the system can reliably, equitably, and efficiently support a high level of distributed energy resources (DERs). Track 2 of the proceeding examines the role of Investor-Owned Utility (IOU) Distribution System Operators (DSOs).

- In 2024, three Gridworks-led workshops culminated in the Future Grid Study (FGS) Report, outlining operational needs, capability gaps, and recommendations for a high-DER future grid.
- The FGS Report findings informed a proposed DER Orchestration Framework intended to facilitate use of DERs as flexible grid assets, defer infrastructure investments, support electrification, and improve grid reliability and customer value.
- DER Orchestration is the coordinated management of DERs by a DSO. Using visibility, forecasting, and control/scheduling tools, DSOs identify location- and time-specific distribution needs and signal eligible DERs (directly or via aggregators) to deliver verifiable services that align with those needs.
- The Framework is intended to integrate multiple operational priorities into a unified approach and enhance the support of critical grid services that provide measurable ratepayer value.

Overview of Application Process

Application: A standalone proceeding in which IOUs propose changes pursuant to formal CPUC orders and statutory requirements. Applications have:

- **Defined scope**
- **Specific requirements**
- **Focused objectives**

Key Characteristics:

- **Process:** Administrative Law Judge and Assigned Commissioner Office establish issue scope, conduct formal hearings, solicit comments, and develop evidentiary record for a Decision
- **Timing:** Typically 12-18 months from filing to final approval, denial, or modification via a Decision
- **Role of Commission staff**: Staff support decisionmakers by providing technical analysis of compliance with statutory and regulatory requirements and policy objectives
- **Resolved by formal Decision**: The Commission must vote to approve a Decision based on the evidentiary record, compliance with statute, and policy objectives such as ratepayer impacts and reliability needs

Addressing Stakeholder Perspectives on IOU Applications for DSO-led DER Orchestration

- Parties submitted comments in April on factors the CPUC should consider when soliciting IOU DSO Applications
  - March 23 ACR identified cost-effectiveness as a key issue in draft guiding principles, and many party comments concurred.
  - Parties can provide perspective on how to sufficiently incorporate principles like cost-effectiveness <u>concurrently</u> through the application process.
  - CPUC could establish working groups for specific issues and incorporate working group recommendations into a Decision via the proceeding record
    - Such as coordination, performance standards, aggregation, and data-exchange protocols
- Cost recovery should **primarily be considered separately in GRC proceedings**
  - Hardware already under review in GRCs should not be requested on a duplicative basis
  - IOUs could propose incremental tech needs **unique** to DER orchestration and **not addressed** in GRCs, subject to Commission review and determination
  - Commission may defer cost recovery proposals to GRCs
  - DER Orchestration should leverage tech already funded, such as DERMS/ADMS.

Draft Guiding Principles for DSO-led DER Orchestration

CPUC's Guiding Principles for DER Orchestration (Draft):
1. Ratepayer Benefit and Protection
2. Technology-Neutral, Performance-Based
3. Locational and Temporal Value Recognition
4. Efficient Operation of the Grid
5. Open Access and Interoperability
6. Transparent Participation Pathways and Compensation
7. Incremental, Evidence-Based Implementation
8. Equity and Customer Protection
9. Cyber-secure and Resilient Operations
10. Preventing Double Compensation

Suggested Additions from Stakeholders:
Optimizing existing grid capacity prioritized over capital investments
Non-discriminatory market access, competitive neutrality, and independent monitoring of DSO and marketplace operator
Neutrality of communications protocol
Demonstrated cost-effectiveness before scaling
Enhance overall grid reliability
Enhance local resilience and edge operability

Other Suggestions for Refinement/Implementation:

- Principles should be clearly defined and prioritized and to enable evaluation of ratepayer/stakeholder needs
- Principles should not slow program development and be revisited with implementation experience

Objectives & Key Discussion Topics

Energy Division Staff

Workshop Objectives

1. **Develop** an application framework for utility DSO-led DER orchestration based on early engagement among parties and build consensus for the application process.
2. **Assess** the foundational principles, participant roles, and operational requirements needed for effective DSO-led DER orchestration and identify outstanding issues
3. **Explore** next steps to be addressed in Applications, such as additional workshops or new working group(s) to resolve outstanding issues and provide recommendations

Key Discussion Topics Overview

Based on questions addressed in the March 23, 2026 ACR, parties are invited to address the workshop goals of the previous slide while discussing the below topics.

1. **Grid Services and Use Cases Enabled by DSO-led DER Orchestration (Qs:1,2)**
2. **Advance, Open Interoperable Communication for DSO DER Visibility and Behind-the-Meter DER Grid Services (Qs:8,10,16,17)**
3. **Dispatch Mechanisms and Aggregator Roles (Q15)**
4. **Cost-Benefit Methodologies and Valuation Frameworks (Qs:3,12,13)**
5. **Incentive Structures and Mechanisms (Qs:6,7,14)**
6. **Evaluating IOU Readiness and Scalability of Rollouts (Qs:5,8,9,11)**

Topic 1: Grid Services and Use Cases Enabled by DSO-led DER Orchestration

- Define and justify the grid services DERs will provide (e.g., reliability, outage avoidance, infrastructure deferral, electrification support).

- Provide examples of use cases that describe how DER orchestration can enable each of these grid services.

Topic 2: Advance Open, Interoperable Communication for DSO DER Visibility and Behind-the-Meter DER Grid Services

- **DER Visibility and Instrumentation**
  - How much DER visibility is needed to control dispatchable DER under a DSO-led orchestration framework?
  - What is the role of ADMS/DERMS to enable communication at necessary granularity, cadence, and latency?
  - What is the role of new technologies (like AMI 2.0) with potential to enhance functionality in this area?
  - Which technologies should be customer-owned or utility-owned, and what are their estimated costs?
- **Communications Protocol**
  - To what extent are existing communication protocols interoperable, including those that are open-access or may reduce reliance on proprietary OEM clouds and enable grid-edge innovation?
- **Security and Privacy**
  - Describe data-sharing frameworks, specifying what DER data should be shared and privacy/cybersecurity safeguards to protect customers
  - Discuss how these approaches ensure timely access to accurate customer usage data, DER data, and other relevant grid data necessary to support DSO functions

Topic 3: Dispatch Mechanisms and Aggregator Roles

- Define roles for utilities, third-party aggregators, and customers under distribution-level dispatch mechanisms to efficiently activate DERs
  - For example, Dynamic Operating Envelope (DOE)-based orchestration, bilateral contracts
- How can DSO-led orchestration frameworks ensure participant DER customers have open access to DSO operations and dispatch opportunities?
  - How should oversight or independent monitoring be considered?

Topic 4: Cost-Benefit and Valuation Methodologies

- Discuss valuation frameworks that could quantify unlocked ratepayer value from DER Orchestration
  - How can DER valuation frameworks be leveraged to optimize existing grid capacity?
- Assess potential of using shared savings mechanisms (SSMs) and cost recovery mechanisms to evaluate the shared value of DER Orchestration

Topic 5: Incentive Structures and Mechanisms

- Describe how DER orchestration implementation can be compatible with the potential rollout of real-time pricing and show value in incremental benefits

- Discuss incentive structures from regulators of other jurisdictions that could be implemented

- Assess the potential of using shared savings mechanisms (SSMs) for DER Orchestration

Topic 6: Piloting and IOU Readiness

- Discuss how the proposed application should demonstrate IOU readiness to implement DER orchestration, such as maturity of ADMS/DERMS, dispatch control mechanisms, and proposed metrics to evaluate effectiveness

- Address how findings from the demand flexibility and equity scenarios of the Electrification Impact Study (EIS) 2.0 can be used to inform areas best suited for implementing DER orchestration

- Discuss possible rollout plans, existing pilot programs, or other potential pathways for achieving the levels of DER orchestration needed to meet affordability and flexibility objectives

- How should the Commission reconcile different states of readiness between each utility so that meaningful progress can be made?

Closing Remarks & Next Steps

Energy Division Staff

Closing Remarks

- Workshop reports that include a high-level summary with presentations attached as an appendix will be requested

- Additionally, post workshop comments will be solicited via a ruling with questions developed by Energy Division staff based on outcomes of discussions in the workshop

- **Reminder:** Workshop #2 on developing a TSO-DSO coordination framework will be held on June 5th, 2026 at the CAISO HQ (250 Outcropping Way, Folsom, CA, 95630)

PG&E's High DER Track 2 Workshop Presentation

High DER R.21-06-017

May 21, 2026

Agenda

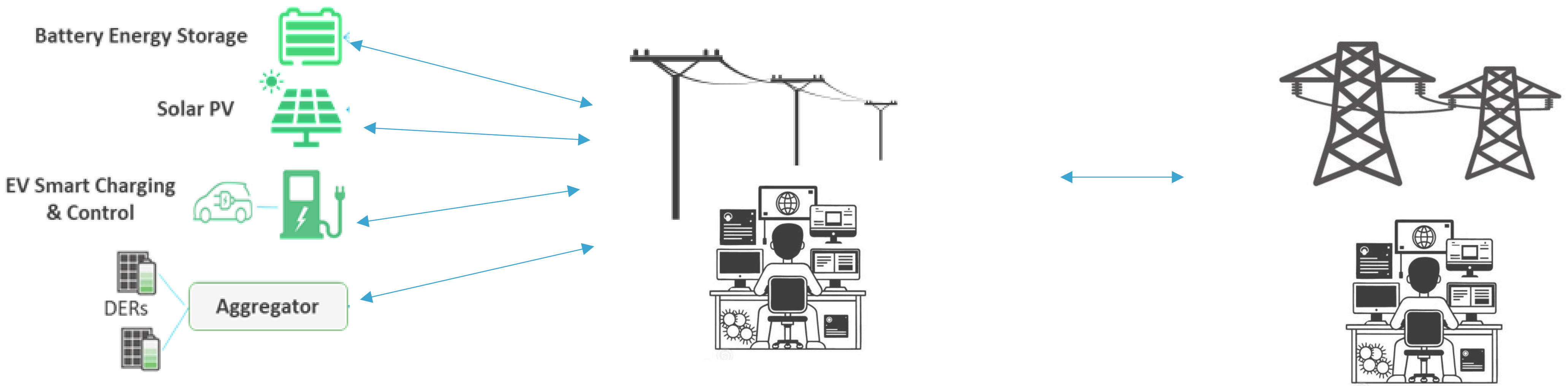
1. PG&E's Load Management Vision & VPP Structure
2. How PG&E as the DSO May Function
3. Where to Focus / Grid Needs Priority Use Cases
4. Implementation Framework
5. Policy Items to Solve
6. Recommendation

Discussion Topics

CPUC Topic Area	Addressed in slides
Grid Services and Use Cases Enabled by DSO-led DER Orchestration	Where to Focus (slide 11)
Advance Open, Interoperable Communication for DSO DER Visibility and Behind-the-Meter DER Grid Services	DERMS Functionality (slide 12)
Dispatch Mechanisms and Aggregator Roles	One VPP Model (slide 9)
Cost-Benefit Methodologies and Valuation Frameworks & Incentive Structures and Mechanisms	Three Types of Flexibility, Three Models (slide 10)
Evaluating IOU Readiness and Scalability of Rollouts	Implementation Framework Starting Point (slide 15)

High DER Future

The TSO ensures system-wide reliability and market coordination, the DSO maintains local grid flexibility, and VPPs optimize distributed resources within those constraints to deliver flexible, scalable grid services.



Virtual Power Plants

- Aggregates and dispatches DERs
- Provides grid services and participates in markets

Distribution System Operator

- Operates and maintains the grid in a safe and reliable manner
- Ensures reliability, safety, and constraint management
- Optimizes system performance

Transmission System Operator

- Balances bulk system, ensures system-wide reliability and market operations

PG&E's VPP model is program construct such that PG&E translates grid needs into a dynamic operating envelope (load shape) for partners, maximizing generation, transmission, and distribution grid value behind the scenes

Affordability is the North Star

Demand flexibility must lower rates for *all* customers, not just participants.

Why now

- Net Energy Metering, load growth + electrification are increasing near-term cost and rate pressure.

How it lowers costs – when done right

- Accelerates electrification and large-load connections.
- Reduces the financial impacts of serving the system and local peaks.
- Enables better grid investment decisions.

PG&E's Load Management Vision

Create a Virtual Power Plant (VPP) structure which aggregates DERs and flexible loads that respond to signals which modify the customer's load to provide grid services

Signals
Includes demand response dispatches and dynamic load limits that can modify a customer's load.

Modify the Customer's Load
Includes load modification programs like DR, behind-the-meter (BTM) resources, and smart technologies.

Provide Grid Services
Includes daily shaping, seasonal peaks, local constraints, and emergency events for generation, transmission, and distribution grid services.

Where California Needs to Go

From

Too many fragmented programs seeking disparate goals across entities (IOUs, CCAs, 3Ps, and CEC) increase costs and limit ability to scale.

Programs deliver variable performance, constrained by **limited single-use cases, aren't designed to meet emerging grid needs**, with limited visibility from aggregators.

One-size-fits-all compensation models that create profit centers for vendors and don't reduce rates

To

Simple, scalable solutions that deliver **net utility cost savings** is the bottom line. If it's not cheaper, if it's not reducing cost, don't do it.

Planning-grade solutions (visible, measurable, dependable), dispatched under frictionless use case switching **that accelerate electrification** or **are meaningfully cheaper** than the alternative (infrastructure build out, etc.).

Competition that drives rates down —value-exchange (free), competitive procurement (lowest cost), and customer-funded

How PG&E as the DSO May Function

PG&E is best placed to serve as the DSO – it is directly accountable for distribution system safety and reliability and uniquely able to coordinate DERs across generation, transmission, and distribution grid needs

	Planning	Grid Infrastructure Upgrades	Select Resources	Deliver Flexible Load	Valuation and Compensation
Current State	• Forecast led Grid Need Assessment (GNA) without DER visibility	• Treat load applications equally • Build to mitigate the system peak risks	• Infrastructure first solutions	• Typical response is wires and equipment upgrade • Flexible Interconnection services as bridging solution via DERMS	• Mostly limited to traditional DR Programs • Export comp for DG and storage compensated through rates • EVs and stand-alone storage are unleveraged
& *Future State*	• Utilize load flexibility and DER visibility to inform grid planning	• Grid needs defined with locational and temporal requirements • Grid needs can be translated into competitive procurement process	• Flexible marketplace • DERs, aggregations, and infrastructure compete equally	• DER orchestration for speed-to-power and mitigating overloading risks via DERMS • Customers are in control of their resources	• Compensation tied to grid value • Transparent bidding and awarding system

One VPP Model: PG&E and Partners are Better Together

PG&E & Partners and Customers

PG&E	Partners and Customers
Needs to see and trust flexible resources.	Customers use familiar partner experiences to set comfort and control preferences once, so load flexibility can operate seamlessly.
Needs to identify and communicate grid need.	Partners plug into one scalable common operating model that supports both demand-side and market-integrated pathways, instead of forcing them to navigate alone.
Needs to own orchestration, measurement, and guardrails.	PG&E translates that flexibility into a dynamic operating envelope (load shape) for partners, maximizing generation, transmission, and distribution grid value behind the scenes.
Has one, 3-model program that can deliver cost-efficient flexible loads across multiple use cases.	Customers benefit based on participation across the 3-models with simple and transparent on-bill credits or rate discounts.

Customers get simplicity, **partners compete on innovation**, and **utilities retain safety, reliability, and planning** accountability.

Three Types of Flexibility, Three Models

	Value-Exchange	Competitively Procured	Customer-Funded
What it is	Utility delivers a service; flexibility comes as a byproduct	Resources with real opportunity costs; vendors compete on price	Large loads pay premium for accelerated service
Examples	Flexible Interconnection services, avoided panel upgrades, smart charging defaults, AMI 2.0 optimization	V2G exports, battery dispatch, t-stats, C&I demand response	Data centers, large commercial seeking speed-to-power
Compensation	None — value is embedded in the service	Competitive procurement — reverse auctions, not administered prices	Customer pays utility — revenue stream for all ratepayers
Who dispatches	PG&E (via DERMS)	Firm: PG&E dispatches directly. Optional: Contractual	PG&E orchestrates
Rate impact	Positive — avoided costs, no payments	Positive — procurement costs << avoided costs	Positive — net revenue

Where to Focus

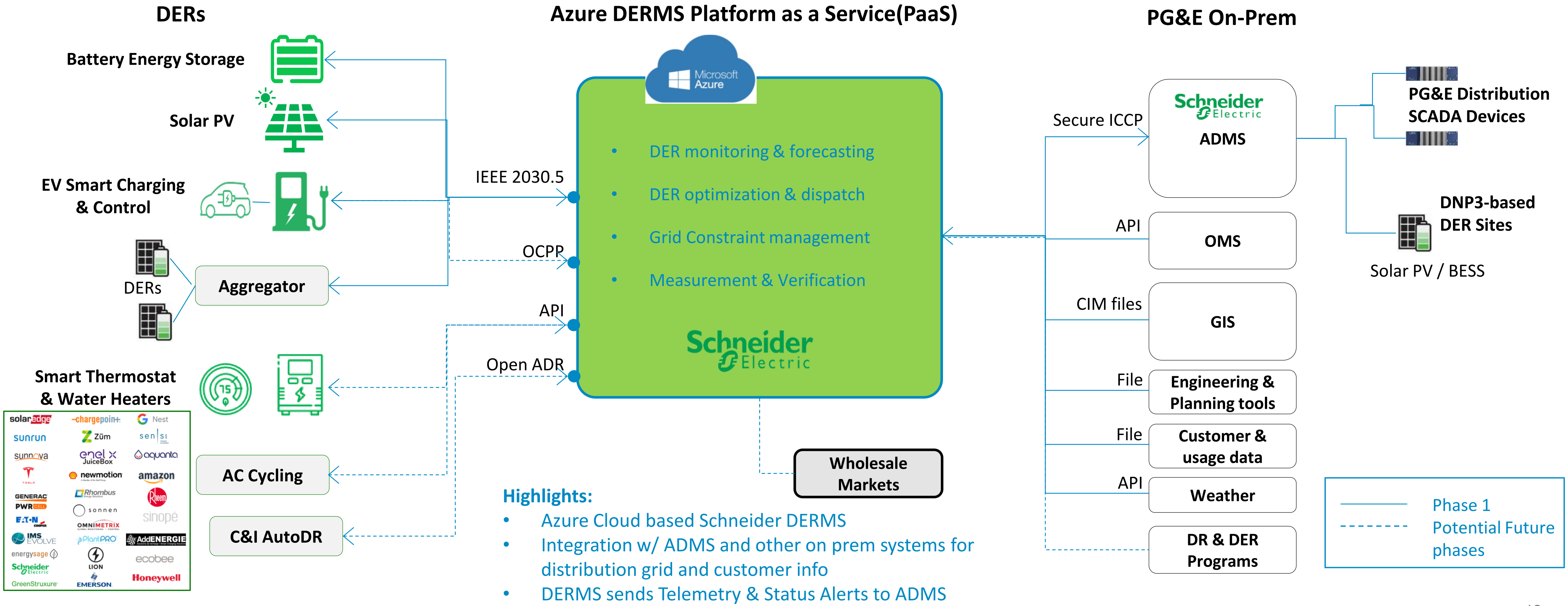
We are intentionally focusing on 3 use cases where flexibility is cheaper than the alternative:

System Peak Reduction	Speed to Power	Resource-Efficient Grid Investments
Deliver firm and reliable MWs at price points that are lower than supply-side alternatives.	Use load management to unlock faster energization and electrification within existing grid limits in a way that puts downward pressure on rates.	Treat demand flexibility as a planning-grade option to balance reliability + affordability across distribution/transmission decisions.

Dispatchable | Verifiable | Locationally relevant | Planning-grade

DERMS Functionality

Advance Open, Interoperable Communication for DSO DER Visibility and Behind-the-Meter DER Grid Services



Speed to Power Example - Flexible Interconnection Services & VPPs

DERMS is connecting controllable loads to the grid at the constrained feeder locations without long delay

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STATUS QUO: Planning Limits for 3.8MW EV Charging Station

Can we use orchestrated DERs to solve for more?

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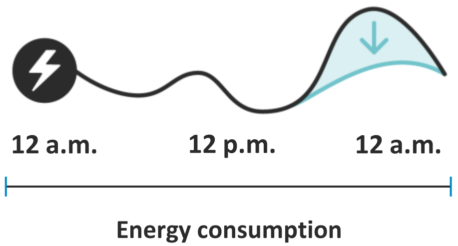
21	100%	100%	100%	100%	100%	100%	75%	76%	73%	100%	100%	100%
22	100%	100%	100%	100%	100%	100%	85%	87%	84%	100%	100%	100%
23	100%	100%	100%	100%	100%	100%	85%	94%	88%	100%	100%	100%

FLEX CONNECT: Can Support Full Request ~90% of the time on Average

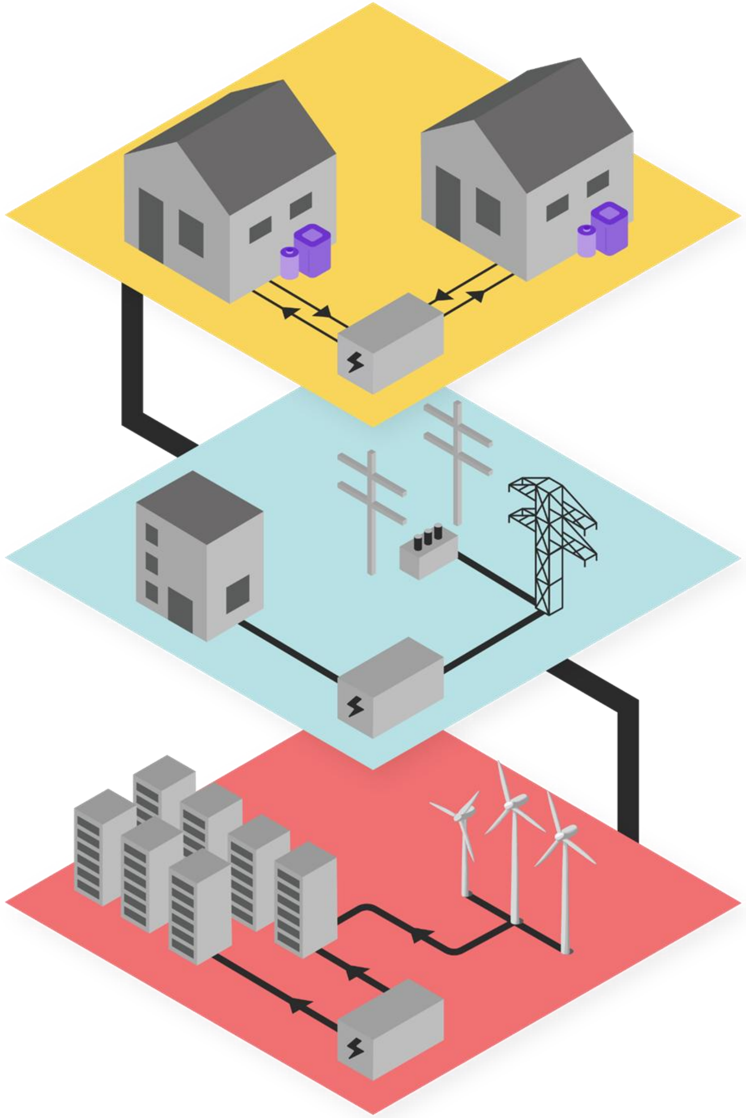
Speed to Power Example 2 – Large Load Interconnection

Homes & buildings with flexible loads

Load shifting



Large Loads with faster interconnects and less community resistance



1. PG&E has identified a line that **multiple data centers will rely on** and is **overloaded during peak hours.**

   PG&E will analyze how power flows across this line and throughout the region to determine at what hours, and in what amount, the line is congested.

2. We will create a VPP of aggregated behind-the-meter resources that respond to grid signals; and develop a program that engages customers in a VPP that delivers firm, flexible load shaping.

3. Once tested and validated, we can expand DERs to reach more customers, manage more load, and scale.

Implementation Framework Starting Point

PG&E favors a phased, evidence-based approach that relies on scaling pilots into programs once value, operational pathways, and measurable outcomes are established.

Sandbox (2026-2027)	Piloting (2028-2030)	Scaling (2030+)
Rapid evaluation of concepts and identification of solutions and approaches with technical viability	*Gather empirical data on performance, costs, and integration challenges while managing risks to ratepayers*	*Scaling occurs only after policy issues are resolved and operational readiness, reliability, and measurable benefits from pilot outcomes*

Phased Outcomes

Sandbox (2026-2027)

- Identify areas of constraints
- Test flexibility marketplace concept in a selected location
- Determine if we can we orchestrate across multi-DER providers
- Resource selection triggers
- Fidelity of signals
- DER visibility
- DER latency, reliability, firmness
- Customer protections
- Cyber-security findings
- Standards based, interoperable (IEEE 2030.5) technology and data sharing frameworks

Ask -- Establish:
- *guardrails on topics that CPUC needs to opine on;*
- *funding and reporting requirements*

Piloting (2028-2030)

Sandbox Plus
- Deploy solution to more areas on grid
- Coordinate across entities (e.g. CAISO, CCAs, ESPs)
- Validate the value proposition with the actual performance results before scaling
- Models to compensate participating customers
- Feedback loop to inform planning processes

Scaling (2030+)

- PG&E provides one signal incorporating all grid needs
- DERs, aggregations, and infrastructure compete equally
- PG&E selects solutions that are planning grade, which provide net savings, including orchestrating across multiple providers to modify customer load
- Customers are in control of their resources & set preferences through partner platforms

Policy Items to Solve Before We Can Scale

Policy alignment is needed across the CPUC, CEC, and CAISO to unlock planning adoption, break pricing floors, and deliver durable net savings to customers.

Planning	Enable Multi-Grid Services	Select Resources	Deliver Flexible Load	Valuation and Compensation
• Allow load flexibility to satisfy system, distribution, and transmission planning needs • Visibility into impact and capabilities of DERs on the grid • Recognize VPPs as load-flex grid resource • Determine how much locational detail is enough for DER planning without increasing vulnerability	• Enable load flexibility that can orchestrate multi-use applications • Provide visibility that enables multiservice participation by DERs	• Ensuring DERs, aggregations, and infrastructure compete equally • Models for a flexibility marketplace • Market power and fairness at highly local levels	• Standards based, interoperable technology and data sharing frameworks • Measurement and Evaluation – using telemetry and/or meter level data & baseline calculations • Revising dual participation policy and enforcement mechanisms	• Clear framework for valuation of grid services • Enable expanded market participation

Key:
Blue – CPUC
Orange- CEC
Grey - CAISO

Recommended Path Forward

PG&E seeks to enable a high DER future through a phased, practical approach – piloting first, learning quickly, and scaling solutions that deliver reliable, cost-effective grid value for customers.

Proposed Next Steps:

- Formalize position of IOU led DSO model
- Establish a process to submit Tier 2 Advice Letter with Memo Account for funding sandbox and piloting activities to continue rapid learnings and innovation, including reporting and accountability requirements
- Continued workshops to resolve outstanding policy issues (in this proceeding and others) informed by use case demonstrations & pilot outcomes

DER ORCHESTRATION: VISION, VALUE, AND PATHWAY TO IMPLEMENTATION

May 21, 2026

EXECUTIVE SUMMARY

- **Vision for Orchestration:**
  - Promote affordability and speed to power through coordinated management of flexible customer resources by the distribution system operator, using real-time data, forecasting, and control signals to deliver location- and time-specific grid services.
- **Value of Orchestration:**
  - Continuous, dependable and automated peak demand modulation at a granular sub-circuit levels to enable capacity project deferral and accelerated energization while supporting customer affordability; will supplement consumer behavior change through demand response and dynamic rates.
- **Implementation Pathway:**
  - SCE proposes a phased pilot-to-scale approach from 2026 through 2033, with early pilots that increase in scale and validate customer participation, grid benefits, and technical systems before scaling successful programs in alignment with grid modernization capabilities (ADMS, DERMS, AMI 2.0); will leverage the capabilities of aggregators.
- **Current Foundation:**
  - SCE has started foundational pilots (e.g., managed charging, storage aggregation) and grid enablement capabilities, with learnings on critical success factors—customer experience, device integration, T&D dependability, and compensation models— but requires additional funding for continued maturation.
- **Regulatory Recommendation:**
  - SCE recommends the CPUC adopt an Advice Letters + Balancing/Memo Account pathway, enabling a quicker path to iterative pilot approvals with cost caps, sunsets, and reporting—and avoiding premature lock-in while preserving Commission oversight ahead of the next GRC cycle.

SCE’S GOALS FOR THE GRID AND THE ROLE OF DER ORCHESTRATION

DEFINING DER ORCHESTRATION

- DER orchestration is the coordinated management of distributed energy resources (DERs) by a distribution system operator (DSO).
    - Includes solar, batteries, electric vehicles, and other flexible loads
    - Leverages forecasting plus real-time data to provide control signals or scheduling to meet location- and time-specific distribution needs
    - May be routed directly from the IOU or via aggregators
- Provides continuous, reliable, real-time load flexibility that will deliver affordability benefits for participating and non-participating customers by accelerating speed to power and maximizing the value of existing infrastructure.
- Leverages a suite of flexible resources, including those put in place through related CPUC proceedings: Flexible Service Connections (Energization), Limited Generation Profiles (Rule 21), and Firm and Non-firm Capacity (High DER Track 3)
- Must be incorporated into planning to capture key affordability benefits (e.g., asset deferral)

EXAMPLES OF ORCHESTRATION

Orchestration Activities	Customer Benefit
Enable dynamic flexible service connection	Earlier energization with less restrictive limitations
Optimize many EVs throughout a neighborhood to reduce circuit and sub-circuit peaks	Defer circuit upgrade (CapEx savings)
Optimize large portfolio of DERs to reduce load	Reduce energy procurement costs
Reduce circuit loading to provide increased operational flexibility	Reduce outage time during planned and unplanned outages
Optimize single customer's BTM DERs to avoid panel and/or service upgrade	Customer/ratepayer savings

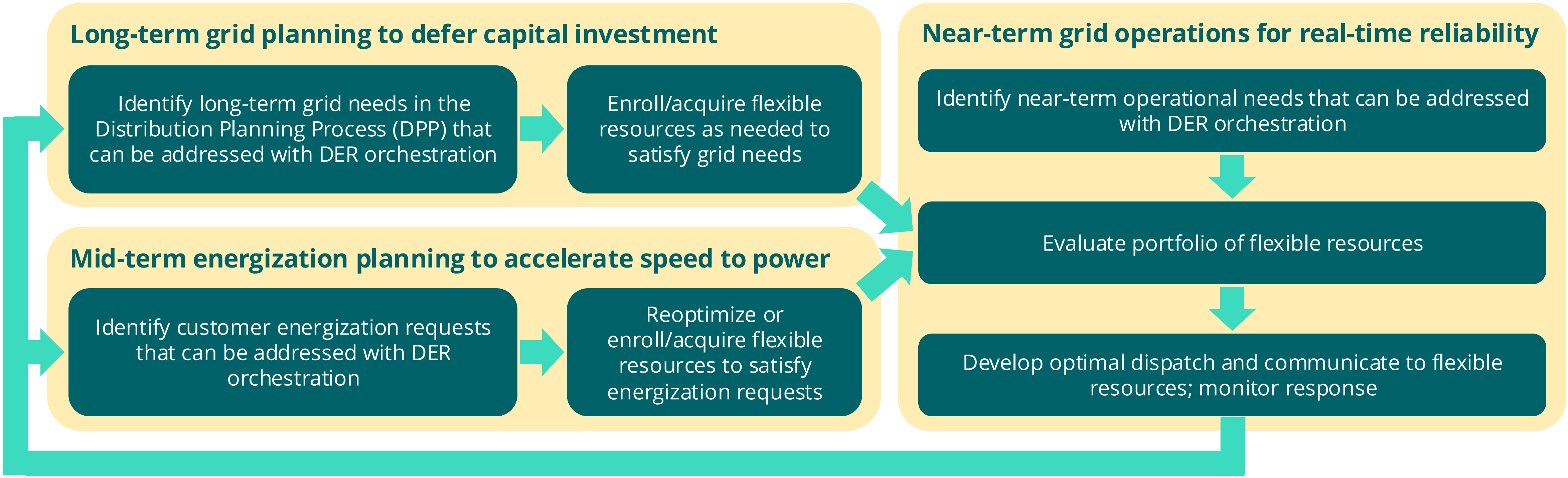
THREE KEY LOAD CONTROL STRATEGIES HAVE DISTINCTIVE BENEFITS

	BENEFITS	CONSIDERATIONS
Demand Response ISO-dispatched, supply-side market integrated*	• Resource adequacy value; reduces capacity procurement • Provides system level reliability and resiliency during emergencies	• High customer impact • No meaningful energy or T&D cost reductions
Dynamic Rates Hourly pricing based on day-ahead energy prices	• Reduces system-level peak loading • If designed correctly, enables the shifting of load to lower-energy-cost, lower-GHG-intensive hours • Potential capacity/transmission benefits if reductions are durable	• Requires capable technology, or engaged, motivated, and flexible customers • Uncertain capacity and grid benefits • Cannot mitigate local reliability issues
DER Orchestration Direct control of flexible loads and generation assets	• Optimized for local distribution benefits & asset deferral • Enables "speed to power" use cases • Addresses secondary peaks via staggered charging • May support outage mitigation and bulk system needs • Can be relied on for planning decisions	• Requires guardrails to prevent duplicating incentives and commands from above approaches • Requires highly flexible loads and DERs

*Note: For this discussion, not including Load-Modifying DR (LMDR) resources embedded or integrated into the California Energy Commission's long-term forecast (e.g. IEPR)

ORCHESTRATION VISION AND IMPLEMENTATION

DISTRIBUTION GRID OPERATORS WILL MANAGE A PORTFOLIO OF FLEXIBLE RESOURCES SECURED IN RESPONSE TO PLANNING NEEDS



HOW IT WORKS: TECHNICAL FUNCTIONS

Grid Layer

ADMS and OE
- Grid Analysis
- Optimization
- Determine DOE

DERMS
Communicate DOE Externally via 2030.5

AMI 2.0 Backend
Usage analysis and disaggregation

Edge Integration Layer

Tech Services
- 2030.5 gateway to communicate with DERMS
- Protocol Translation (OpenADR, OCCP, device APIs, etc)

Edge Analysis and Optimization
- Considering DOE, local constraints, customer parameters
- Create device level schedule and dispatch

OEM Cloud
May be necessary to connect to device

AMI 2.0
- Usage analysis and disaggregation
- Potential comms gateway
- Potential edge optimization device

Customer Layer

Customer DERs
- EV / EVSE
- HVAC
- Solar and Storage
- Other

Add'l Device
May be necessary to enable communication to edge layer

Program Vertical

Program Design
- Eligibility rules
- Performance requirements
- Incentives

Customer Engagement
- Marketing
- Enrollment
- Customer parameters and preferences

Performance and Settlements
- Monitoring
- Verification
- Payment
- Remedial actions

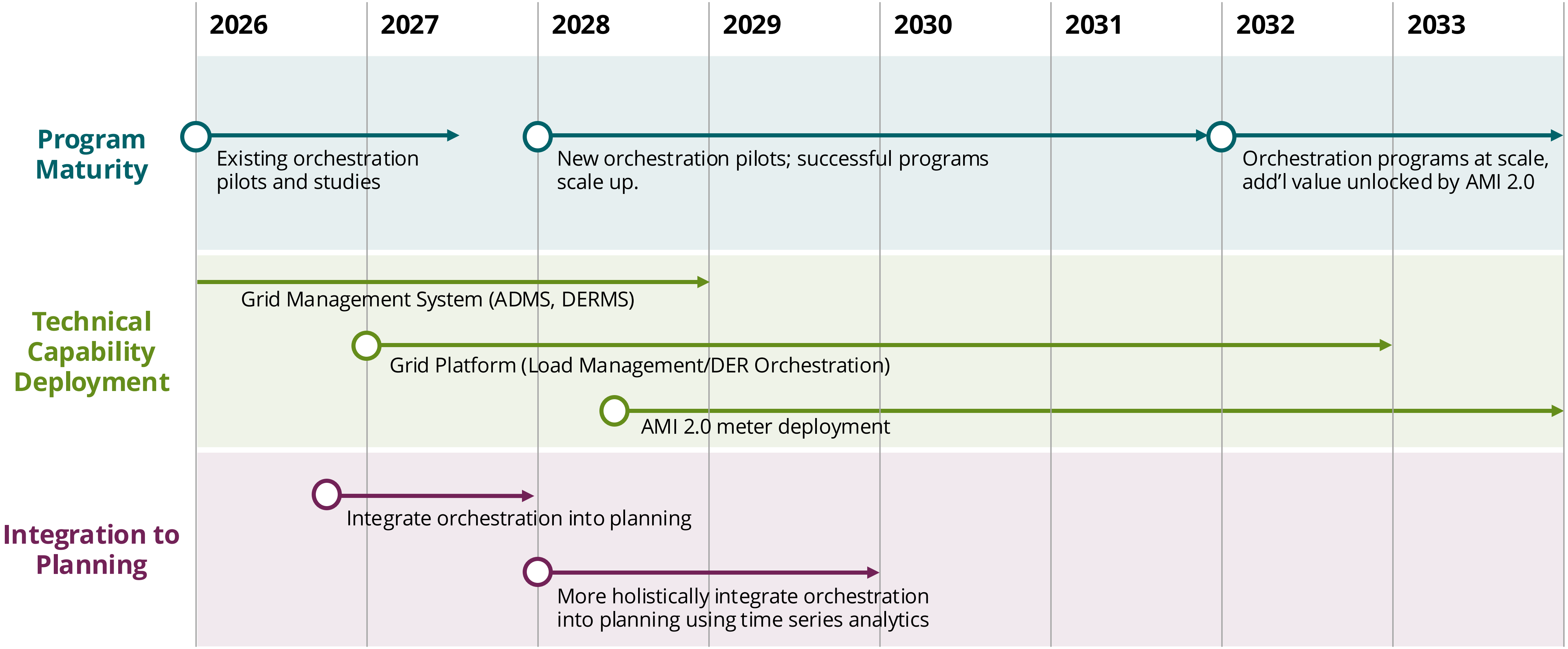
Legend: DSO | DSO or Third-Party | Customer

DER ORCHESTRATION PROGRAM OPPORTUNITIES

	Critical Success Factors	Relative Maturity (H,M,L)	Current State	Program Opportunities
1	**Customer Experience (CX)** (Enrollment, Program Satisfaction, Digital CX)	**Med**	**Leverage Existing/Planned Work:** Dynamic Rate, DR & EV studies/programs are translatable	Continue to test enrollment, onboarding, and experience for different types of flex across devices/segments
2	**Device / DER Integration** (Multi-Device Dispatch)	**Low - Med**	**Leverage Existing Work:** Studies testing multi-device concept but for event-based, bulk dispatch	Expand multi-device concept at distribution level
3	**Customer Behavior / T&D Dependability** (Integration into Planning)	**Low**	**Analysis Focus:** Multiple studies on potential; pilots/studies focused primarily on event-based / bulk dispatch	Test customer behavior for different types of load flex at distribution level
4	**Compensation & Partnership Model** (Payment and Operations)	**Low**	**Limited Learnings:** Dynamic Rate, DR, and EV pilots/studies provide clues on compensation /partner models	Test incentive structure and optimization of third-party partnerships

SCE has established certain foundational elements for DER Orchestration; however, several critical success factors need to be matured to achieve goals

IMPLEMENTATION TIMELINE



REGULATORY PATHWAY

SOUTHERN CALIFORNIA EDISON®

RECOMMENDED REGULATORY PATHWAY

- **Proposed Decision should adopt the policy foundation to enable orchestration**
  - Adopt DER orchestration concept and affirm orchestration as a priority DSO operational capability
  - Adopt guiding principles (see next slide)
  - Affirm value of early-stage pilots (leveraging existing funds) and learning-focused implementation; provide guidance on future pilots (to be funded incrementally)
  - Establish high-level guardrails (cost discipline, reporting, accountability)
- **Following the PD, further regulatory process should guide ongoing implementation and provide funding**
  - Advice Letter process (coupled with memo account) enables a faster, iterative approach aligned with the needs of a new orchestration program
  - An application process could be feasible, but should be narrowly focused and targeted.

Advice Letters + Memo Account (Preferred Approach)	Application Key Parameters (Alternative Approach)
• **Tier 1 / Tier 2 Advice Letters** for pilot initiation, modification, and scaling	• **Narrow, time-bound application** authorizing a program window, not a permanent program
• **Dedicated memo or balancing** account with defined cap and sunset (pre-next GRC)	• **Phase 1: expedited approval** of limited pilot budget and activities
• **Ability to file multiple ALs (**e.g., 2027, 2028, 2029) as learning evolves	• **Phase 2: refinement and adjustment** informed by Phase 1 evidence
• **No presumptions about final orchestration model** or GRC treatment	• **Application explicitly does not lock in final models** or future GRC outcomes

COMPARISON OF ALTERNATIVE PATHWAYS

Topic	Advice Letters + Memo Account (SCE Preferred)	Application
Alignment with incremental, evidence-based development	**Very strong** – iterative approvals support testing, fast-failing, and course correction based on real-world evidence	**Moderate** – can support learning, but tends to formalize assumptions earlier
Speed and responsiveness	**Faster** – ALs typically operate on months-long timelines and can be re-filed as needed	**Slower** – even expedited applications involve litigation and longer decision cycles
Ability to adapt and pivot	**High** – pilots can be adjusted, expanded, or discontinued through subsequent ALs	**Lower** – changes often require amendments or reopening the proceeding
Transparency and Commission oversight	**Ongoing –** iterative oversight through regular AL filings and reporting	**Concentrated** – oversight at application milestones; fewer adjustment checkpoints
Funding ahead of next GRC	**Yes, with flexibility but likely lower total funding** - Enables funding of pilots prior to late-2029 GRC, with safeguards and transparency; likely requires memo or balancing account and overall funding potential may be lower	**Yes, with constraints** – Provides funding authority, but with greater delay and rigidity
Risk of premature lock-in	**Low** – avoids fixing governance, valuation, or technology choices before evidence is available	**Higher unless guarded** – mitigated only if explicitly non-precedential and time-limited

CONCLUSION

SOUTHERN CALIFORNIA EDISON®

DER ORCHESTRATION WILL UNLOCK AFFORDABILITY AND SPEED TO POWER

Vision: What DER Orchestration Enables	Implementation: How SCE Gets There	Regulatory Pathway: How to Enable Learning Without Lock-In
• Enhance affordability • Improve speed to power • Increased grid efficiency	• Start with targeted pilots, then scale deliberately • Integrate planning, portfolio management, and operations incrementally	• Establish policy foundations in the PD • Use Advice Letters with a capped memo account • Defer durable design choices

SDGE™

High DER Future – R.21-06-017
Track 2 DER Orchestration Workshop

May 21, 2026

Today's Presentation

- SDG&E's Position and Current State
  - Overarching vision: Framework first; Applications are readiness-driven
  - Pilots may be required prior to Applications
  - SDG&E's current ADMS/DERMS status
- Addressing the Six Key Discussion Topics listed by CPUC Energy Division
  1. Grid Services and Use Cases
  2. Open, Interoperable Communication and DER Visibility
  3. Dispatch Mechanisms and Aggregator Roles
  4. Cost-Benefit Methodologies and Valuation Frameworks
  5. Incentive Structures and Mechanisms
  6. IOU Readiness and Scalability
- Closing Topics

SDG&E's Overarching Vision

Framework First

The DER Orchestration Framework should be adopted in Track 2 — through structured workshops and written party comments — before applications to implement orchestration are filed.

Applications are Readiness-Driven

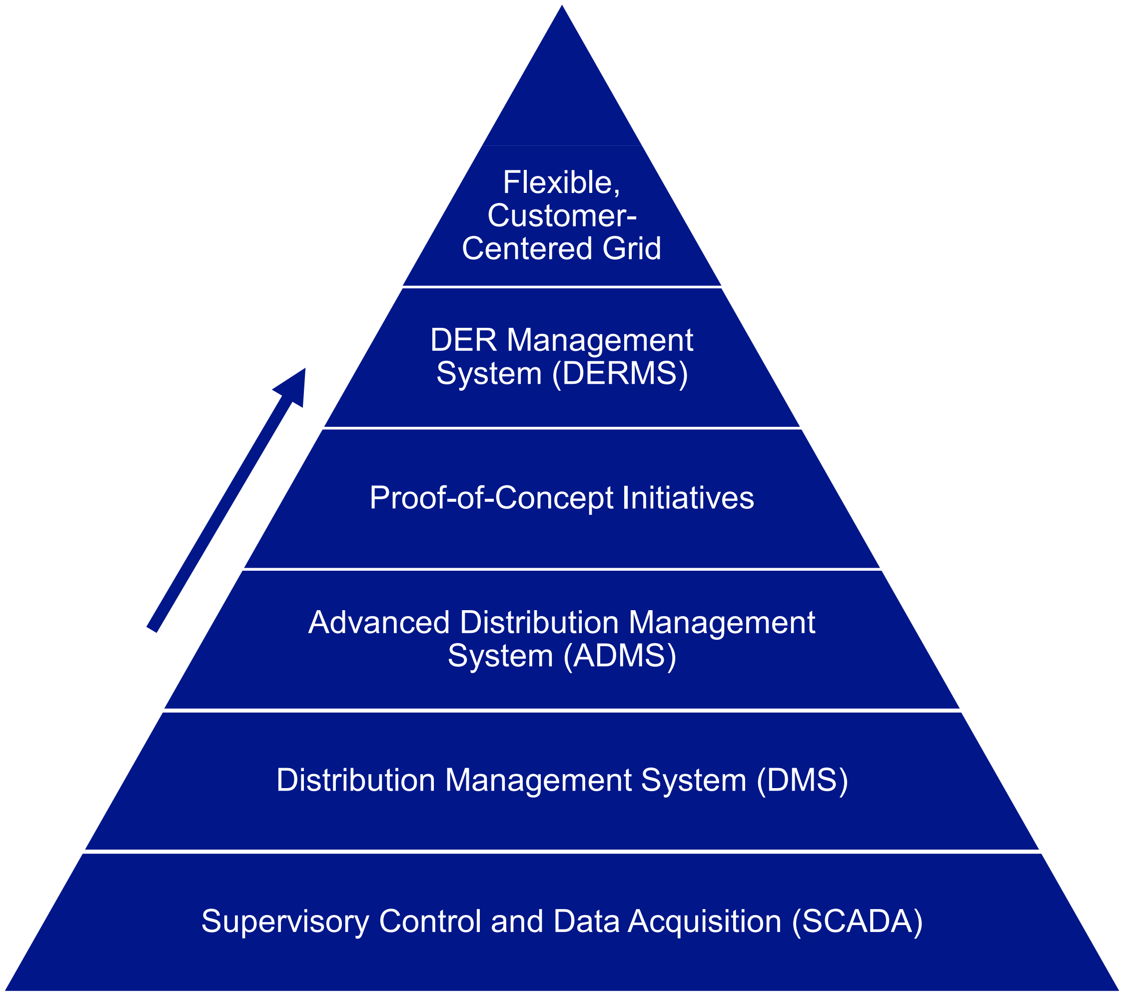
A utility should only file an application "if it is determined that [it] can begin implementation in a measured, cost-effective, and reliable manner." The Commission should not mandate applications nor impose timelines.

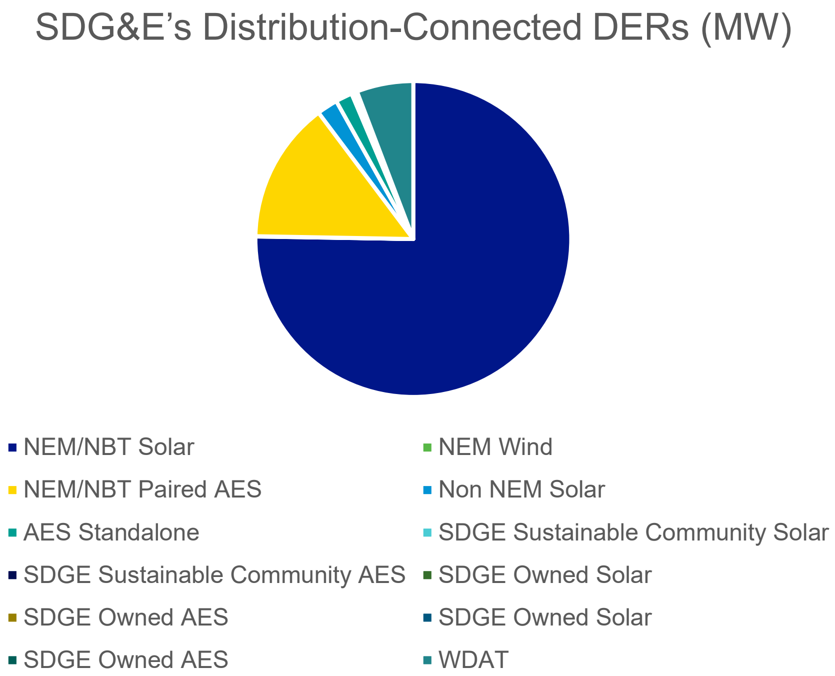
Applications Consistent with Framework

Commission review of Applications focuses on whether proposed programs:

- clearly identify the distribution-service, costs, and benefits
- are consistent with the Framework

Visibility, Management, and Control Roadmap





Total: 3282.8 MW

Framework-First DER Orchestration Roadmap

A structured approach to provide net rate payer benefit

01 Framework Development and Adoption

Establishes core principles (safety, interoperability, cybersecurity, cost recovery) to enable DER orchestration.

02 Utility Readiness and Capability Build-Out

Enhances systems, visibility, and DERMS procurement aligned to the framework to avoid stranded investments.

03 Targeted Pilot Programs

Tests technical and commercial viability using established tools and framework as progression criteria.

04 Readiness-Driven Applications

Which propose DER-provided distribution services based on proven pilots and grid needs, ensuring regulatory compliance and ratepayer value.

05 Scaling and Sustained Operations

Deploy DER programs based on proven pilots and grid needs, ensuring regulatory compliance and ratepayer value.

Topic 1

Grid Services and Use-Cases Enabled by DSO-led DER Orchestration

Topic 1: Grid Services – Overview

- SDG&E identified the following potential distribution services for DER Orchestration Programs in Opening Comments (at 5-7):

Possible Programs at Application Stage	Near-term viability
Real-time thermal overload mitigation	Limited; device signaling and aggregator-readiness dependent
Voltage control via DER dispatch	Utility-side measures generally lower cost
Distribution upgrade deferral	DIDF experience suggests limited commercially viable opportunities at ratepayer-beneficial compensation
Abnormal conditions support	Operationally complex; pilot validation needed
Bridging solutions/speed-to-power	Already being implemented by PG&E and SCE. SDG&E has not had a need.
WDAT charging limits	Operational where interconnection agreements include limits
V2G	Emerging; pilot-scale investigations

- **Principle:** Programs should be anchored to specific distribution needs and supported by a cost-effectiveness showing.

Topic 1: Moving Forward

- Adoption of a Framework is the correct place to start.
  - The Framework will define what an Application needs to include, for example:
    - (a) The grid need that the DER-solution will mitigate
    - (b) The conventional utility solution that addresses the need (establishes the baseline against which the cost-effectiveness of the DER-solution is estimated)
    - (c) DER compensation where applicable
    - (d) Estimated costs (including compensation) and benefits of the DER-solution
    - (e) DER performance attributes required to address the grid need
    - (f) How DER performance will be measured
    - (g) Remedial solution in the event of DER non-performance
- Workshops will help to refine the Framework

Topic 2

Advance Open, Interoperable Communication for DSO DER Visibility and Behind-the-Meter DER Grid Services

Topic 2: Open, Interoperable Communication – Visibility

Fit-for-purpose visibility: Match visibility to grid service needs (avoid one-size-fits-all)

Visibility Pathways

Aggregator-level for managed fleets

Direct device for large or utility-dispatched DERs

Customer meter (BTM) view reflects net grid impact

ADMS/DERMS Capabilities

Day-ahead feeder load forecasting

Real-time or near-real-time feeder telemetry

DER registry integration

Scaling

Visibility, latency, and granularity sstandards refined through pilots & program design

AMI 2.0 data will likely enhance visibility, system modeling, and data validation

Position: Protocols, Data & Technology Ownership

Protocols

- No mandated protocol (IEEE 2030.5, OpenADR, etc. = implementation choice)
- Focus on interoperability & open access, not specific technologies
- Vendor licensing limits are structural → require state/standards action

Data Sharing

- Governed by existing privacy & cybersecurity rules
- Use current CCA data-sharing processes
- Architecture choices (DERMS, interfaces) evolve with implementation

Technology Ownership

- Utility owns utility-side (front-of-meter) systems
- Customer/aggregator owns customer-side (BTM) devices
- Communications defined via contracts & tariffs

Topic 3

Dispatch Mechanisms and Aggregator Roles

Roles under DSO-led orchestration

- **Roles**
- **DSO (Utility):** Defines grid needs, sets terms (tariffs/contracts), verifies performance
- **Aggregators:** Manage DERs, commit capacity, handle customers/devices, bear performance risk
- **CCAs:** Participate as LSEs using existing data-sharing pathways
- **Customers:** Participate directly or via aggregators/CCAs

- **Principles**
- Dispatch & architecture are flexible (e.g., Dynamic Operating Envelopes, contracts, real-time vs scheduled)
- Driven by grid needs & program design — not mandates

- **Implementation Approach**
- **Open access:** No “winners/losers” — any qualified provider can participate
- **Utility role:** Define needs + procure services transparently

Topic 4

Cost-Benefit Methodologies and Valuation Frameworks

Topic 4: Cost-Benefit Methodology

- California Standard Practice Manual (CSPM) could serve as a reference. Supplemented for distribution-specific value (Opening Comments at 7-8)
- Examples of distribution-specific elements the Framework could specify:
  - Locational and temporal avoided-cost recognition (marginal cost at constrained locations; duration of deferral)
  - Comparison against traditional utility solution
  - Full incremental cost accounting (platform, telemetry, settlement, M&V, compensation, remedial actions in the event of non-performance)
  - Bill-impact analysis (separate from net-benefit analysis)
- Compensation discipline (Reply Comments at 11-12):
  - Capacity payments to DERs on grid-wide basis in advance of identified locational needs (as may be identified via the DPP), creates a high probability of paying for DER capabilities that are not needed
  - Compensation should be limited to amounts that provide ratepayer benefit

Topic 5

Incentive Structures and Mechanisms

Topic 5: Incentive Structures – Shared Savings & RTP

Shared Savings Mechanisms (SSM):

- SDG&E did not propose an SSM in opening comments and remains neutral pending further investigation
- SSM design is a significant ratemaking matter that may be better addressed in a dedicated venue

Real-Time Pricing (Opening Comments at 17):

- DER orchestration and real-time pricing are largely separate workstreams
- DER orchestration relies on utility-identified needs and DER dispatch in response
- Real-time pricing relies on voluntary customer response to prices
- Customer response to real-time prices should be reflected in load forecasts (IEPR, day-ahead operational forecasts)

Other jurisdictions (UK, Australia)

- Useful learning sources; not directly transferable to California
- Workshop review appropriate; binding adoption of specific inventive structures would be premature

Topic 6

Evaluating IOU Readiness and Scalability of Rollouts

Topic 6: IOU Readiness – SDG&E Specifically

SDG&E's readiness state
No DERMS today; procurement targeted 2027
Pilot-capable environments anticipated post-2027
Foundational ADMS and day-ahead forecasting capabilities are operational and being refined

How the Commission should consider differing readiness
Adopt a common Framework that establishes consistent guiding principles, methodology, performance-metric categories, and readiness criteria.
Allow utility-specific implementation pathways within that common Framework
Do not mandate uniform filing timelines or scope requirements – utilities should file applications when they have identified cost-effective opportunities and developed readiness to deliver
Recognize that pilots may require DERMS. Some pilots may be possible with the operational infrastructure currently in place.

Topic 6: Pilots

Pilots serve four functions framework-level policy alone cannot supply (Reply Comments at 7)
Technical feasibility under real operational conditions
Commercial viability at compensation levels that provide ratepayer benefit
Operational integration (telemetry latency, signal reliability, aggregator performance, cybersecurity, settlement, interoperability)
Participation pathways tested at manageable scale before service territory-wide deployment

For SDG&E, pilots may depend on DERMS
DERMS infrastructure may be needed before SDG&E can responsibly run DER dispatch pilots; e.g., where the DER program is dependent on location- and time-specific grid conditions.
DERMS procurement target: 2027-2028; pilot-capable environments post-2027

Where pilots demonstrate viability, scaled programs can follow

Topic 6: Use of EIS2

EIS findings are useful context – but not a pilot-siting tool

EIS Part 2 quantifies long-term electrification-driven upgrade costs at the system level

EIS does not identify specific feeders, circuits, or time-bounded grid needs with the certainty that cost-effective DER orchestration will require

DPP is refreshed annually; provides a more current and reliable basis for identifying distribution needs

Specific pilot siting should follow from DPP outcomes and identified, planned distribution needs

Closing Topics

Cost Recovery, Proposed Process &
Conclusion

Cost Recovery

- Three distinct cost categories (Reply Comments at 9):

Cost Category	Recovery Vehicle
Foundational capital (AMDS, DERMS, Communication infrastructure)	GRC and Grid Modernization Plans
Framework-establishment costs (if applicable)	Memorandum account, subject to subsequent reasonableness review
Program-specific costs (if applications are filed and approved)	Program-level cost-recovery mechanism approved with the program

- Any Commission direction or requirement that a utility implement or begin DER orchestration should recognize whether existing funding is adequate and, if not, provide a dedicated cost recovery mechanism/pathway to comply with Commission requirements

Proposed Process

- The Commission should adopt the Framework in Track 2 through a structured series of workshops, supported by written party comments, culminating in a Commission decision.
- SDG&E supports additional workshops and/or a working group.
- After the Framework is adopted:
  - Utilities file Applications when ready
  - Readiness requires identification of specific distribution needs, development of DER programs that mitigate the need, and Commission approval of those programs
  - Readiness may be contingent on pilots with promising results
  - Depending on the DER program design, readiness may be contingent on DERMS development progress

Conclusion

1. Commission adopts the Framework in Track 2
2. Utility submits Applications proposing programs under which DERs provide distribution services
   - Applications identify the distribution need, estimate program costs and benefits, and demonstrate consistency with the Framework
3. Commission approves the programs proposed within the Applications
4. Commission authorizes necessary cost recovery mechanisms
5. Commission should clarify how DER Orchestration interfaces with Demand Response Rulemaking (R.25-09-004) and other regulatory mechanisms under which Demand Response programs are proposed and program costs recovered
   - Demand Response is generally considered to fit under the DER umbrella
   - To date, Demand Response program proposals have had their own timeline, cost-effectiveness tests, approval procedures and cost recovery mechanisms
   - It is currently unclear if the Commission intends that Applications that propose Demand Response programs, would be the mechanism by which the programs are approved and cost recovery authorized

Q&A

DER Orchestration

Anthony Abi Abdallah
Distribution Planning and Policy

May 21, 2026

Goals of DER Orchestration

- Use existing grid capacity more efficiently.
- Avoid or defer upgrades where cost-effective.
- Support electrification and faster energization.
- Improve reliability and operational flexibility.
- Reduce total ratepayer costs.

Applications Are Premature

1. Foundational framework issues remain unresolved.
2. Party comments, including the IOUs', indicate that it is premature to determine whether IOU applications are necessary, and that the Commission should first develop a DER orchestration framework.
3. Cost recovery should be reviewed through GRCs, not a new application.

The Commission should decide whether applications are needed only after it develops an orchestration framework.

Issues to Resolve First

1. **Cost-Benefit Framework:** Approach to determining whether DER Orchestration creates net ratepayer value.

2. **Performance / Evaluation Metrics:** Define what the IOUs must show before scaling.

3. **Accountability and oversight:** Establish reporting, data, participation, and performance rules.

4. **Cost Recovery:** Review DER Orchestration costs that the IOUs have already recovered through the grid modernization component of GRCs.

Build the Framework from Existing Work

Work Already Underway	What It Should Answer
GRC / Gridmod • DERMS • Non-wires Alternatives • Local Orchestration	**Readiness + Costs** • Existing Capabilities • Target Locations • Incremental Costs • Expected Benefits
Pilots / Early Deployments • Managed Charging • Battery Controls • Aggregated DERs • Local Orchestration • Flex Connect	**Pilot Learnings** • Upgrade deferral potential • Customer participation • Control performance • Comms / technology / data access

Proposed Process

The following depicts a possible process pathway for a DER Orchestration framework:

Q2-Q3 2026	Q3-Q4 2026	Q1 2027	Q1 2027	Q2 2027
Commission Decision →	Working Group →	Working Group Report →	Party Comments →	Framework Adoption Decision

1. Working group develops use cases, data needs, and evaluation methods.
2. Parties comment on the working group report before Commission adoption.
3. Commission adopts the framework, metrics, evaluations, and oversight standards.
4. IOUs apply the adopted framework in GRC filings before scaling.

A Practical Way Forward

1. Do not order IOU applications now.
2. Develop the framework and rules first.
3. Build on work already underway.
4. Give the Commission a decision-ready record.
5. Use the adopted framework to guide future scaling and GRC review.

Questions?

California Community Choice Association

DER Orchestration Workshop
R.21-06-017

May 21, 2026

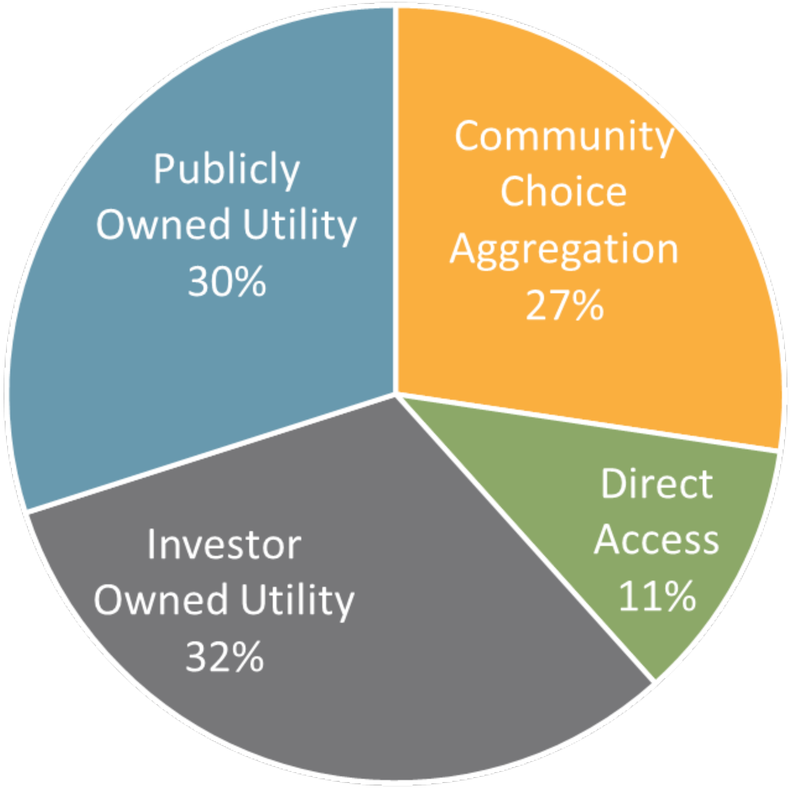
CCA Role in DER Orchestration

CalCCA Interactive CCA Map & Address Lookup:

https://cal-cca.org/cca-map/

CCA Launch Timeline

2026 Percentage of CA Retail Load by Energy Provider



Energy Provider	2026 Deliveries (GWh)
Investor-Owned Utility	77,550
Community Choice Aggregator	66,945
Energy Service Provider (DA)	26,896
Publicly Owned Utility	73,250
Statewide Electricity Deliveries	**247,105**

Source: 2025 IEPR Forecast. California Energy Demand 2025-2050 Forecast - Planning Forecast

Community-Centered CCA Programs

- As CCAs continue to grow and flourish in California, they are advancing innovative, industry-leading projects and programs
- Many are now focusing on DERS, including Virtual Power Plants
- Several CCAs now operate DERMS platforms to directly control customer DERs and smart appliances

"CCAs can design and deploy innovative initiatives and community-centered programs that provide financial and environmental benefits and can respond to communities' needs."

-UCLA Luskin Center for Innovation

Sonoma Clean Power | Your Public Electricity Provider

Hablamos Español | Meetings & Agendas | MENU

Alerts Through GridSavvy Rewards

Stay Cool, Save Energy, and Keep Your Neighborhood Bright With GridSavvy Rewards From Sonoma Clean Power.

GET $25 WHEN YOU ENROLL

Save Energy. Share Energy. This Summer and Beyond.

When it's really hot, everyone uses more electricity. To make sure there's enough to go around, there's an easy way to help: **Save Energy. Share Energy.** Saving energy when asked helps your whole neighborhood. When you save energy, you share energy, to help keep the lights on in the neighborhood **all summer long**.

Earn rewards by lowering your energy use when electricity use is high. By reducing electricity use during peak hours, you can help decrease the need for natural gas power plants and prevent power outages.

When you sign up for GridSavvy Rewards, you'll get paid for helping us power the electric grid with more local, clean energy. SCP will send an energy saving alert when there is high demand for electricity. You choose how to reduce your energy use.

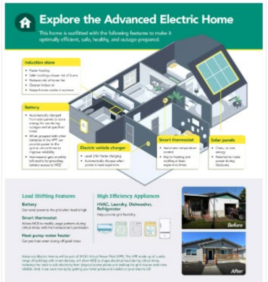
SIGN ME UP!

MCE

How to Help California's Grid? Go Virtual

At first glance, there's nothing atypical about the small gray house located on a quiet residential street in Richmond, Calif. But look further and you'll see that it's the first piece of a revolutionary new type of power plant. Unlike traditional plants, you won't find any massive cooling towers or transmission lines. That's because this electrified home is part of a virtual power plant, or VPP.

How It Works



The homes MCE is equipping to participate in its VPP are outfitted with numerous grid-smart devices that not only provide grid flexibility but also make for a better experience for the homeowner.

VPP in the News

News Release – November 3, 2025

Peninsula Clean Energy, Silicon Valley Clean Energy Jointly Launch Demand Flexibility Initiatives

Lunar Energy's Gridshare software will enable new battery and other programs to reduce customer energy bills and harmful emissions

PENINSULA CLEAN ENERGY | SILICON VALLEY CLEAN ENERGY

REDWOOD CITY/SUNNYVALE, CA – Peninsula Clean Energy (PCE) and Silicon Valley Clean Energy (SVCE) are jointly launching cutting-edge demand flexibility efforts, highlighted by a Distributed Energy Resource Management System (DERMS) that will support a range of new programs.

The DERMS is a powerful software platform that both agencies will use as a foundation to expand their clean and smart energy programs. The new platform will enable participating customers to easily, automatically and comfortably shift daily electricity use – earning them direct bill savings, while also helping to reduce grid costs and harmful emissions.

PCE and SVCE have contracted with Mountain View-based Lunar Energy for its Gridshare DERMS platform to connect, control and optimize devices located at customer sites.

ORANGE COUNTY POWER AUTHORITY | YOUR CLEAN ENERGY CHOICE

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Residential Battery Rebate Program

Power up and protect your home with a battery energy storage system

Overview | Eligibility | Resources | Application

Power Up and Reduce Electricity Costs with a Home Battery

Orange County Power Authority's (OCPA) Residential Battery Storage Rebate Program helps customers manage their energy consumption and save money by storing electricity during lower-cost, off-peak hours for use during more expensive, on-peak hours ("load shifting"). Adding battery backup can protect your home from outages and help strengthen the electric grid. A battery will also reduce greenhouse gas emissions.

Rebate amount per customer: $1,000.

Clean Power Alliance Approves New Program to Install Virtual Power Plant and Provide Low Income Customers Access to Solar Energy at No Cost

CPA CLEAN POWER ALLIANCE

Clean Power Alliance Approves New Program to Install Virtual Power Plant and Provide Low Income Customers Access to Solar Energy at No Cost

CPA will work with Haven Energy to install networked solar and battery storage systems on eligible low-income residents' homes to provide localized clean power and significant savings on customer electricity bills while managing peak energy demand

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SAN JOSE CLEAN ENERGY

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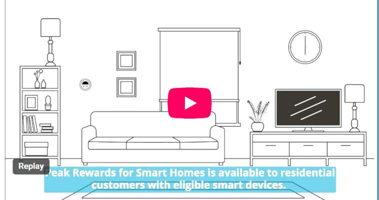
PEAK REWARDS FOR SMART HOMES

Let your smart device earn you rewards!

Peak Rewards for Smart Homes makes it easy to earn rewards. Simply enroll an eligible smart device in the program and you'll automatically start earning rewards each quarter. We communicate directly with your device to make small adjustments that keep you comfortable and earn you rewards. You are always in control and can override our signals when needed.



Ava Community Energy Announces Ambitious Virtual Power Plant Initiative to Help its 2M Customers Optimize Their Energy Investments While Relieving Stress on the Grid

April 24, 2025

Lunar Energy's Gridshare DERMS Platform Selected to Underpin the Effort

Oakland, CA April 24, 2025 – Ava Community Energy (Ava) today announced the launch of its comprehensive Virtual Power Plant (VPP) strategy. VPPs are systems that aggregate distributed energy resources (DERS), such as electric vehicles and home batteries, so they can be controlled remotely to enhance grid reliability and lower costs.

SAN DIEGO COMMUNITY POWER

ABOUT COMMUNITY POWER | WAYS TO SAVE | BILLING & RATES | HOW DO I?

Smart Home Flex

Enroll smart thermostats and connected water heaters to earn rewards and reduce energy use during hours of high demand.

CALCCA
ADVANCING LOCAL ENERGY CHOICE

DSO Operational Roles Must be Considered Prior to Settling on a DER Orchestration Framework

A Robust Record Should be Built Before the CPUC Commits to an Orchestration Framework

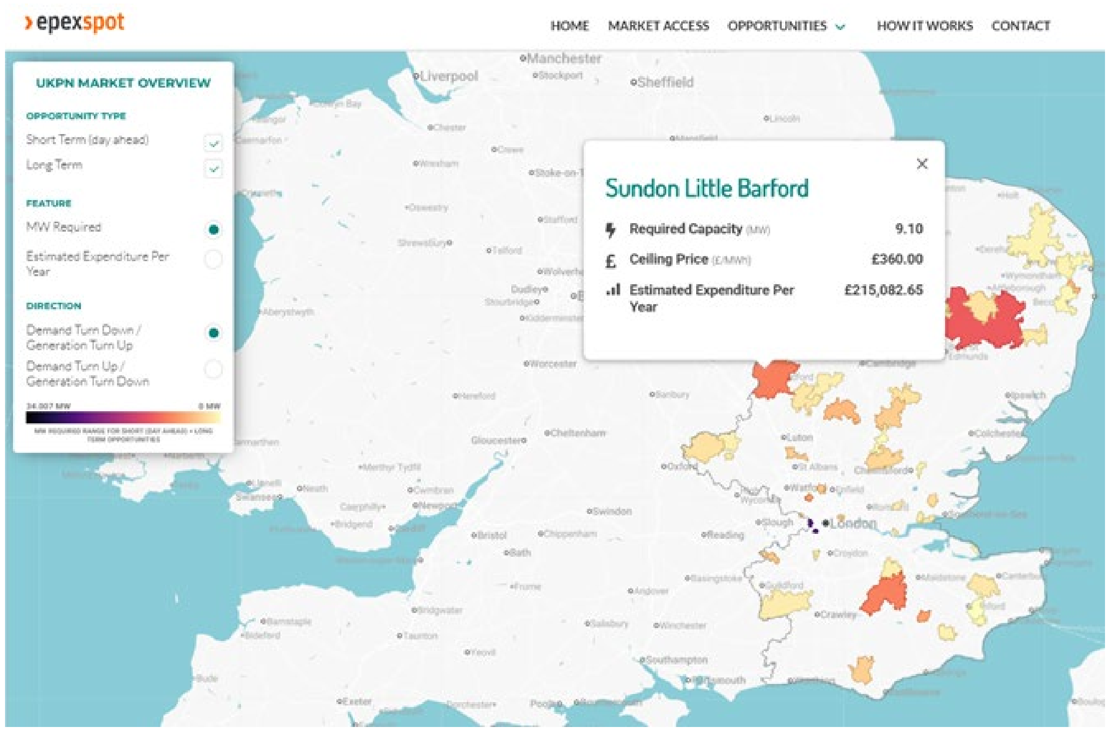
- **Significant Unresolved Concerns Over Potential Conflict of Interest for an IOU Serving as the DSO Must Be Resolved**
  - The "build versus buy" bias inherent in the existing IOU business model must be addressed
- **An IOU-Led DSO Model Deviates from FERC Findings on Market Independence**
  - The CPUC should leverage FERC's rulings on market independence for RTO/ISOs to guide exploration of a DSO framework
- **Since the FGS Ruling, There Have Been Significant Changes in the Deployment of Flexibility Marketplaces Outside of California**
  - Worldwide, markets continue to evolve and expand (*e.g.*, the UK demand flexibility market)

Significant Recent Changes in Flexibility Markets Require CPUC Consideration

- **Flexibility markets have grown in numbers and size since the Future Grid Study Workshops**
  - The British demand flexibility market grew from 1.6 GW of flexibility services contracted in 2021 to 9 GW in 2025
  - At least two new marketplace operators_announced partnerships with major DSOs in 2024
  - The UK-based independent market operator Piclo launched its Marketplace platform across the US in 2025
- **These new developments warrant further investigation by the Commission to inform the development of a DER orchestration framework in California**

Committing to a Specific DER Framework Without Further Development of the Record May Result in Higher Costs, Less Participation, and Fewer Benefits

- **Decisions about DER orchestration platforms and communications protocols will impact costs and DER participation**
  - IOU enterprise ADMS/DERMS are not easily scalable and not designed for market administration
  - The IOUs' preference for IEEE 2030.5 could limit aggregator participation and increase costs for customers wishing to participate
- **IOU conflicts of interest could reduce distribution deferral opportunities and increase costs**



UK Power Network Local Flex Market Map

DER Orchestration Framework Comparison

- **IOU ADMS/Enterprise DERMS**
  - Provides visibility into operational needs of distribution grid and control of IOU-managed DERs
  - Designed for top-down control of IOU-managed DERs rather than orchestration of third-party and CCA-managed DERs
    - Not scalable or transparent; ill-suited for orchestrating edge DERs
- **IOU Grid-Edge DERMS**
  - Allows limited integration of non-IOU DERs
  - Relying on an IOU edge DERMS limits market participation and stifles innovation
- **Independent Marketplace Operator**
  - Greater level of flexibility and scalability, reduces IOU conflicts of interest, greater transparency, and enables broad participation of DERs
- **Independent DSO**
  - Greatest transparency and market participation, but most complex and difficult to deploy

Benefits/Risks of an Independent Flexibility Market

	Attribute	Outcome
+	Greater market neutrality	Increased participation and competition
+	More competition and innovation	Potentially lower costs and higher efficiency
+	Fewer conflicts of interest	Reduced potential for overbuilding and potentially lower costs
+	Greater transparency	Greater oversight and stakeholder trust
+	Better regional, CAISO, and LSE coordination	Broader participation and increased benefits
–	Increased complexity	Increased risk for implementation and regulatory delays
–	Requires high level of coordination with IOUs	Potential operational friction with IOUs during emergencies, depending on oversight
–	Potential data access issues with IOUs	Lack of transparent data access undermine market effectiveness
–	Potential cost duplication	Potential for increased administrative overhead in early stages of deployment

Benefits/Risks of an IOU Run Flexibility Market

	Attribute	Outcome
+	Single entity operates the grid and market	Quicker implementation
+	Tighter operational integration	More consistent alignment with safety and reliability objectives
+	Lower administrative complexity	Familiar regulatory structure, but requires new oversight and safeguards to minimize conflicts of interest
+	Easier cost recovery	Ease of financing platform deployment through retail rate recovery mechanisms
–	Greater potential for conflicts of interest	Could suppress DER participation, increase risk of overbuilding the grid, and decrease market efficiency
–	Reduced innovation	Systems and process improvements may lag technology advancements and discourage participation
–	Potential for vendor lock-in	Potential for reduced competition and interoperability
–	Less customer trust	Potential for reduced DER participation

The Commission Should First Adopt a Robust Set of Guiding Principles

CalCCA Recommended Additional Guiding Principles to Inform Commission Consideration and Decision-making

- Nondiscriminatory market access, operations, and dispatch;
- Independent monitoring and oversight of the DSO and market functions;
- Optimization of existing distribution grid capacity before authorization of capital investments;
- Competitive neutrality of the DSO and marketplace operator;
- Fair compensation for flexibility services; and
- Timely access to accurate customer usage, DER, integration capacity analysis, and grid data.

RULEMAKING 21-06-017 | HIGH DER FUTURE | TRACK 2

Mass-Market DER Orchestration

Maximizing Ratepayer Value, Resiliency, and Competitive Access in California's DSO Framework

CPUC DSO Orchestration Framework Workshop

Thursday, May 21, 2026 | CPUC Auditorium, 505 Van Ness Ave., San Francisco

Presented on behalf of Utility Consumers' Action Network (UCAN)

Samuel Golding

President, Community Choice Partners · Consultant to UCAN

UCAN Counsel of Record

Jane Krikorian, Staff Attorney

jane@ucan.org

WHY THIS FRAMEWORK MATTERS

The Affordability Stakes — and the Architectural Risk

THE RATEPAYER MULTIPLIER

$1 → $4

Every $1 of utility infrastructure spending incurs ~$4 in additional ratepayer cost over its life — O&M, financing, and return on equity.

— 350 Bay Area Opening Comments, Apr. 20, 2026

- **Mass-market DERs can provide significant orchestration value, grid resiliency & ratepayer equity.** EVs, batteries, heat pump water heaters, HVAC controls, smart panels, etc. represent untapped, significant, and growing grid-edge capacity owned by customers.
- **Orchestration is, first, a CapEx-avoidance tool.** Its job is to defer the substation and transformer upgrades that drive billion-dollar increases in the IOUs' distribution plans.
- **"DSO-led" must not mean "IOU-monopolized."** The architectural choices made here will determine whether ratepayers capture savings or pay twice for wires + redundant utility IT.

Distribution upgrade cost forecasts through 2040 — wide divergence, large orchestration opportunity

$42–48 B	$25 B	~55%	$5–18 B
IOU EIS Part 2 statewide aggregate (Base → Equity)	PAO DGEM 2025 central — ~40–48% below IOU sum	Unit-cost reduction in DGEM 2025 vs. DGEM 2023 (real project data)	Avoidable upgrades via managed charging / orchestration (PAO)

Co-Equal Aggregator Participation Requires Open Architecture

Mass-market DERs already exist in California ratepayers' homes. Unlocking them at scale is not a technology problem — it is an architectural one. Three design choices determine whether aggregators can actually participate, or whether the framework simply layers a new utility intermediary between the customer's resource and the grid value it can provide.

1 Co-Equal Aggregator Participation

Aggregators — VPPs, CCAs, ESPs, third-party DER providers — must be able to dispatch their own fleets at the grid edge under verifiable performance envelopes, on comparable terms to any utility-run program. Without that, mass-market DERs cannot scale: every customer's smart battery, EV charger, or heat-pump water heater is mediated by a utility-controlled bottleneck.

2 Protocol Neutrality

Co-equal participation only works if the framework accepts open communications standards — OpenADR alongside IEEE 2030.5 — instead of mandating a single device-level protocol. Single-protocol mandates create OEM licensing costs, IT bottlenecks, and integration friction that throttle the very aggregator scaling co-equal participation is meant to enable.

3 Open Access Infrastructure

Protocol neutrality is necessary but not sufficient. Aggregator participation at scale needs common platforms — a DER Registry for visibility, a Data Hub for multi-entity data exchange via API, and a Flexibility Market Platform for transparent procurement of services. These three statewide platforms are the open-access infrastructure on which co-equal participation operates. (See next slide.)

STRUCTURAL SOLUTIONS

Open Access Infrastructure

Interrelated, mutually reinforcing — UCAN's long-standing recommendation (Future Grid Study Comments, Dec. 2024; restated in DF and Track 3 filings).

1 Statewide DER Registry

WHAT IT DOES

A comprehensive database of all DERs — retail BTM, distribution-interconnected, and microgrids — and of aggregator portfolios. Tracks location, capabilities, generation/load/storage, asset & inverter type, etc. Provides visibility to DSOs and CAISO.

2 Statewide Data Hub ("API of APIs")

WHAT IT DOES

A neutral, multi-entity data hub — starts with certified Green Button Connect 4.0 across IOUs, then evolves into a single API standard for customer usage data, DER data, and grid data shared between DSOs, CCAs, ESPs, aggregators, and CAISO.

3 Statewide Flexibility Market

WHAT IT DOES

A distribution-level marketplace where DSOs & LSEs contract for flexibility services from DERs and aggregators on transparent terms. Integrates with DER Registry, communicates through Data Hub, coordinates with CAISO wholesale markets and transmission operations.

DEMAND FLEXIBILITY WORKING GROUP RECOMMENDATIONS

The forthcoming Demand Flexibility working-group report (R.22-11-013) is expected to recommend evaluation of the Statewide DER Registry and Statewide Data Hub.

HIGH DER PARTY RECOMMENDATIONS

CalCCA strongly recommends the Commission evaluate an independent flexibility marketplace operator.

CAISO recommends evaluation of "*centralized data platform*".

AEU recommends "*common platforms promoting open access principles*" & that "*visibility, communications, and dispatch systems, platforms, processes, and protocols*" be "*consistent and/or common across IOUs*".

(Clean Coalition, CEDMC, 350BA, and Nexamp generally support open access and market enabling solutions.)

THE CENTRAL CHOICE

Process & Timeline: More Pilots, or Procure the Platform Now?

The IOUs propose three siloed multi-year buildouts; UCAN proposes deploying a statewide demand-flexibility market platform now — a path already operating in Connecticut and live in California for CCA Resource Adequacy.

IOU PATHWAYS — MULTI-YEAR, SILOED, SDG&E: NO MARKET ACTIVITY 2026–27

PG&E

Tier 2 AL + memo account for "sandbox" + "piloting" + "scaling"

Sandbox 2026–27 · Piloting 2028–30 · Scaling 2030+ (Workshop slide 15)

SCE

Advice letters + balancing/memo account; GRC backstop

Pilot-to-scale 2026–2033 · Foundational tech in 2029 GRC (Workshop slide 11)

SDG&E

Framework-first; no DERMS until 2027; "no Commission-imposed timeline"

Framework in Track 2 · Pilots post-2027 · Programs ~2030 (Workshop slide 19-20; Reply §II.A.2)

UCAN — PROCURE THE PLATFORM; ACTIVATE THE MARKET IN 12–18 MONTHS

- **Connecticut grid service market:** PURA awarded Piclo $1.82 M in Dec. 2023. Marketplace launched July 2024 across both Eversource + UI territories. A 7-month deployment with ~35 MW procured in pilot window!
- **California RA market:** Piclo launched a CA marketplace in Feb. 2025. 70+ MW now offered to CCAs for Resource Adequacy .
- **Statewide Deployment Proposal:** Months 0–6: RFI → ED proposal →Track 2 decision authorizes Statewide Demand-Flex Market Platform; Months 6-9: competitive procurement. Months 9-15: utility integration, DER aggregator onboarding & solicitations. Months 15+: dispatch at high-value locations, continuous procurements → refinements & scaling.

BUSINESS AS USUAL

SDG&E: zero distribution-level flex MW under contract for ratepayers in 2026 or 2027.

Three separate buildouts, three readiness states, three procedural vehicles — and the wires plan proceeds unchallenged on the wires-plan schedule.

THE COST OF DELAY

IOU EIS Part 2 forecasts $42–48 B in distribution build-out through 2040; PAO DGEM 2025 central is closer to $25 B — and $5–18 B of those upgrades are avoidable through orchestration. Each year of pilots locks in upgrades a market could defer.

Procedural Path: 12 Months from Decision to Go-Live

Five phases. Each builds on the next. Each has an owner. The Commission can authorize this sequence in Track 2.

MONTHS 0–3 — RFI & WORKING GROUP

Owner: CPUC Energy Division

- ED issues an RFI to scope platform requirements + integration architecture
  - — Flex market
  - — DER Registry
  - — Data Hub
- Working group convenes; parties + vendors provide feedback on scope, governance, cost-recovery

MONTHS 3–6 — PROPOSAL, COMMENT, ORDER

Owner: CPUC / parties

- ED proposal submitted on the record
- Party opening + reply comments
- CPUC order authorizes competitive procurement of the three platforms

MONTHS 6–9 — COMPETITIVE PROCUREMENT

Owner: CPUC ED (or designee)

- ED (or its designee) issues RFP for platform(s)
- Vendor evaluation; competitive selection of neutral third-party operator(s)

MONTHS 9–15 — INTEGRATION & REGISTRATION

Owner: Selected vendor(s) + IOUs

- Vendor(s) integration with each IOU's ADMS / AMI / CRM / GIS systems
- DER aggregator and asset onboarding + registration begins
- First utility flexibility solicitations open for bid

MONTHS 15–18 — GO-LIVE

Owner: Vendor, IOUs, LSEs & aggregators

- First MW under contract delivering distribution services
- Continuous procurement cycles for grid services, deferral, RA capacity
- Performance + cost evaluation feeds next-cycle scope

UCAN
UTILITY CONSUMERS' ACTION NETWORK
San Diego's Utility Watchdog

Questions welcome.

Presented on behalf of Utility Consumers' Action Network (UCAN)

Samuel Golding
golding@communitychoicepartners.com

UCAN Counsel of Record

Jane Krikorian, Staff Attorney
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Core principles for a local-first DSO framework

Ben Schwartz
Policy Director
626-232-7573 mobile
ben@clean-coalition.org

Clean Coalition (non-profit)

Mission

To accelerate the transition to renewable energy and a modern grid through technical, policy, and project development expertise.

Renewable Energy End-Game

100% renewable energy; 25% local, interconnected within the distribution grid and ensuring resilience without dependence on the transmission grid; and 75% remote, fully dependent on the transmission grid for serving loads.

A DSO must manage more than energy balancing

Clean Coalition

Service	Key to Delivering Service
Energy Balancing	Capacity of real power (W)
Voltage Balancing	Location of reactive power (VAr)
Frequency Balancing	Speed of sourcing or sinking real power (W)

The Duck Curve Chart only addresses Energy Balancing, but Inverter-Based Distributed Energy Resources (IBDER) can provide unparalleled balancing of all three dimensions.

Rising grid costs make local optimization essential

Clean Coalition

- **Transmission Access Charges (TAC):** These are volumetric ($/kWh) charges assessed to customers to recover costs of historical and present investments in transmission infrastructure.
  - The chart below shows that the average TAC rate in the IOU service territories has more than tripled over the last 11 years.
  - Since 2008, the IOU's base annual Transmission Revenue Requirement (TRR) has increased from $4.6 billion to $21 billion.
- **Future Transmission:** CAISO estimates that $30 billion in transmission capex will be needed over the next 20 years (for the high-voltage system only, not including low-voltage).
- The upfront capital cost of a transmission project is only 10% the full cost in nominal dollars shouldered by the ratepayers when considering profit and O&M over 50-year transmission depreciation schedules.

Nominal costs

Asset value capital cost ($100 base)	$100
Return	$197
O&M	$631
Total nominal ratepayer cost per $100 investment (50 years)	**$928**

Real costs, discounted for inflation

Discount rate	2.19%
Asset value capital cost ($100 base)	$100
Return, discounted	$140
O&M, discounted	$296
Total discounted (real) ratepayer cost per $100 investment (50 years)	**$536**

In nominal dollars, total lifetime ratepayer cost is nearly 10x the initial capital cost; O&M accounts for 68% of this because it increases much faster than inflation. In real dollars (constant value dollars, accounting for inflation), the total lifetime cost is 5x the initial capital cost, and O&M accounts for 55% of this.

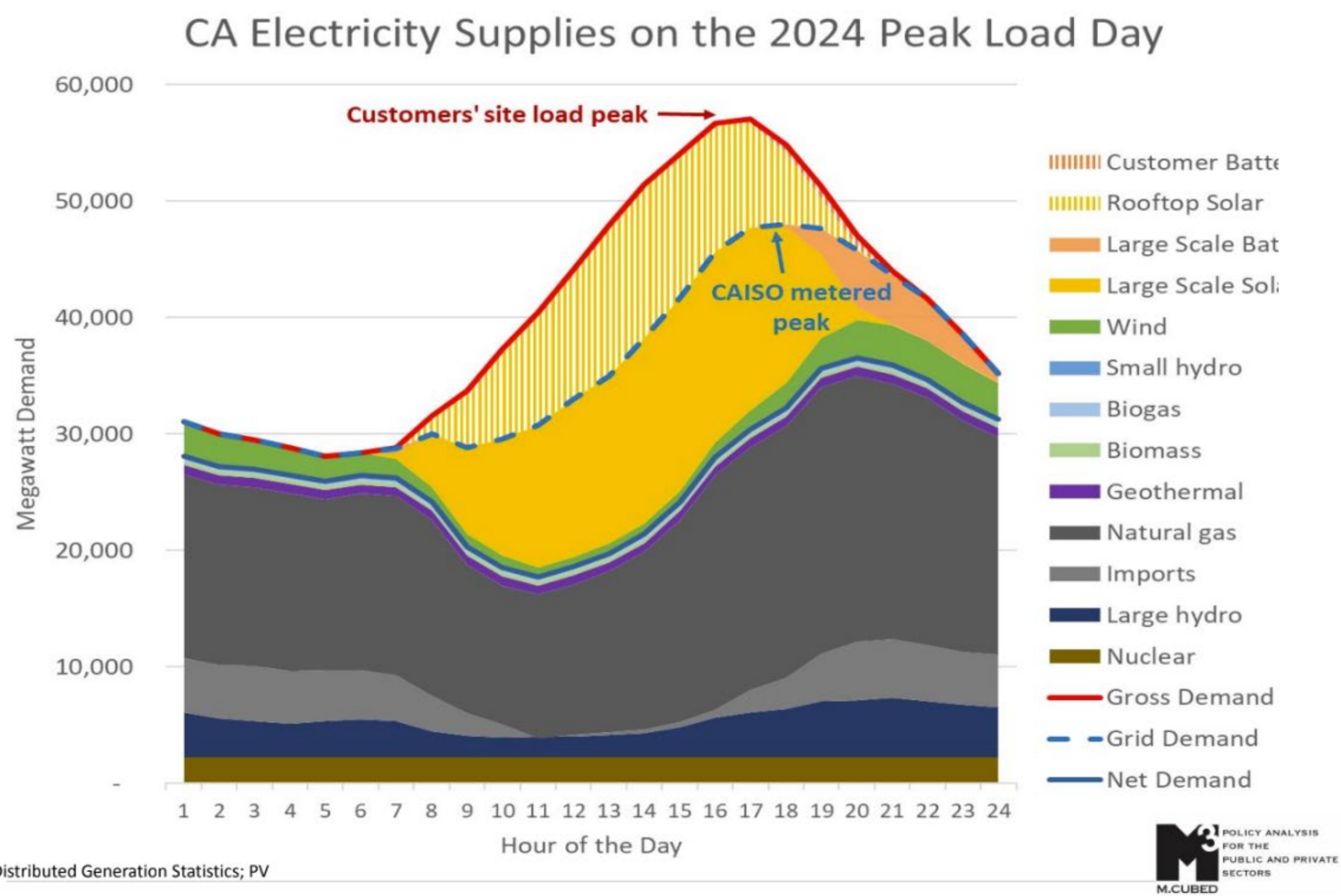
2025 TAC (wholesale rates)

PG&E	$0.037/kWh
SCE	$0.0153/kWh
SDG&E	$0.066/kWh

Significant BTM capacity already exists

Clean Coalition

NEM Customers Serve Nearly 20% of Peak Demand



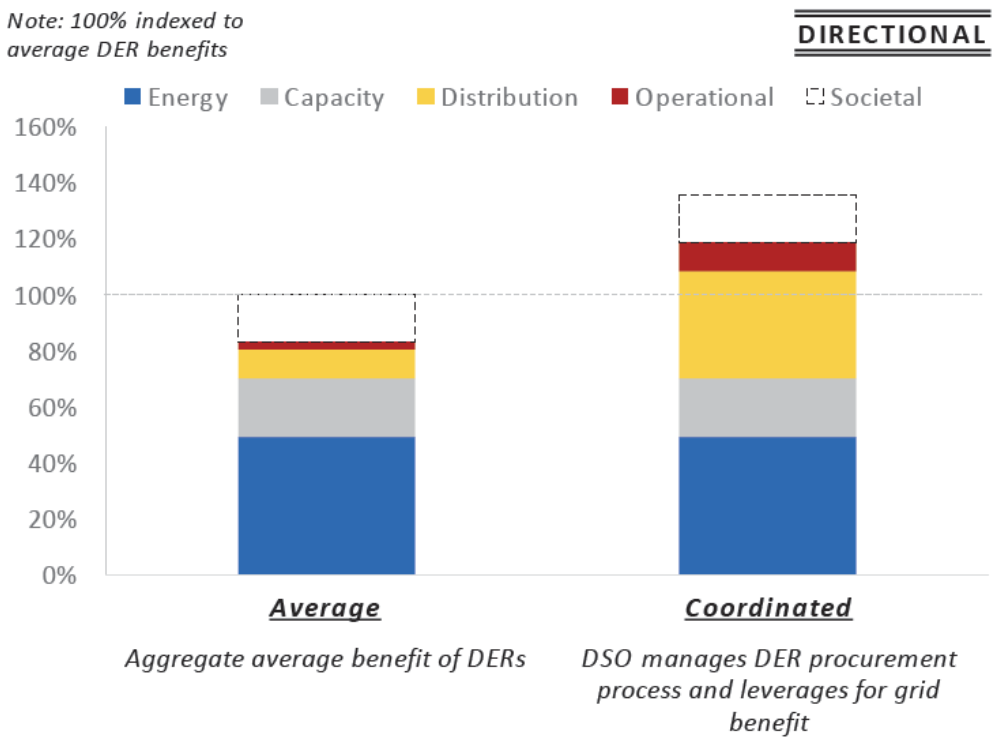
Source: CAISO website; California Distributed Generation Statistics; PV Watts

A well-implemented DSO is an affordability solution

Clean Coalition

These conditions require a distribution-level operator whose incentives are aligned with local optimization, DER participation, and avoided infrastructure cost.

Figure 5: Impact of DSO coordination of DERs on benefits to grid



Southern California Edison, September 2016

7

Designing a Local-First DSO

Clean Coalition

A DSO should be designed to optimize the local grid first.

Its role should be to balance local supply and demand to the maximum extent feasible before relying on upstream imports or exports by:

- Using DER to provide voltage, frequency, resilience, and other local reliability services.
- Maximizing utilization of existing infrastructure through non-wires alternatives.
- Supporting a local market structure that creates transparent, bankable value streams for DER.
- Managing external grid interactions at the T-D interface.

The DSO's financial incentives should primarily be aligned with speedy interconnection, timely energization, efficient DER operation, and avoided infrastructure costs.

Building an Effective DSO

Clean Coalition

- The framework should preserve a clear boundary between distribution optimization and bulk-system dispatch.
- DER should be compensated for local energy, voltage/frequency support, congestion relief, deferred T&D investments, and contributions to local fossil peaker plants retirements.
- The DSO should use open-access procurement or market mechanisms, not bilateral opaque utility discretion.
- The DSO should operate grid-level DERMS and coordinate with third-party and CCA edge DERMS through open, interoperable interfaces.
- The DSO should be evaluated on local balancing, avoided infrastructure cost, interconnection speed, and DER participation.
    - Utility earnings should be tied to performance outcomes, not capital deployment alone.
- The DSO framework should minimize conflicts of interest between local grid optimization and capital incentives tied to upstream infrastructure.

DSO Valuation: Making Local Value Bankable

Clean Coalition

A DSO cannot function if local value is acknowledged in theory but not compensated in practice.

- Existing frameworks including LNBA/ACC recognize that DER have locational value, but do not address the full value stack for a resource deployed in a particular location.
  - The ACC focuses on generic system avoided cost value that does not incorporate future benefits from reduced load, congestion, and transmission requirements.
  - LNBA has often been implemented in a way that is too coarse and planning-oriented, making it insufficient as a bankable operational value framework for a true DSO.
- A DSO should work with applicants and resource owners to optimize a value stack that maximizes ratepayer benefits.
- Preventing double compensation is important, but it should not become an excuse to erase legitimate, distinct value streams such as local congestion relief, avoided distribution upgrades, voltage support, flexibility, and resilience-related system benefits.

DSO-Enabled Microgrids

Clean Coalition

- The DSO should be allowed to identify substation areas where aggregating DER into a future Community Microgrid configuration creates measurable local reliability & resilience value.
  - The Commission has approved Substation-level Microgrid projects before, such as the Calistoga Substation Microgrid project.
- The valuation framework should be able to recognize that value before the full portfolio is completely built out to properly incentivize resource deployments.
  - Grid forming and black start capabilities are required for a Community Microgrid. Both are project cost drivers that could be properly incentivized in recognition of the value of resilience.

GLP Community Microgrid as a DSO Use Case

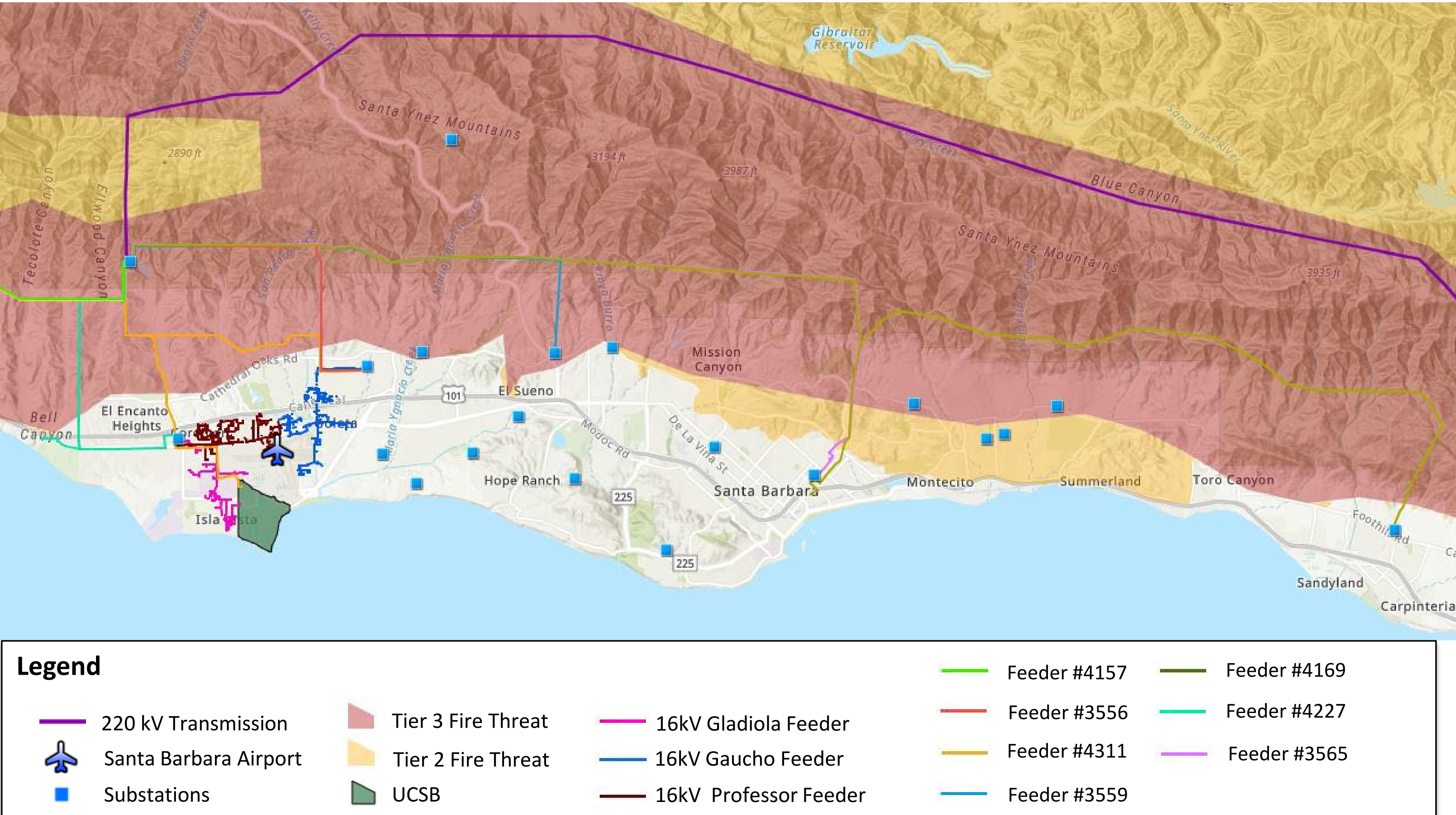
Clean Coalition

The Goleta Load Pocket (GLP) demonstrates the need for DER-driven reliability and resilience

- GLP spans 70 miles of California coastline, from Point Conception to Lake Casitas, encompassing the cities of Goleta, Santa Barbara (including Montecito), and Carpinteria.
- GLP is highly transmission-vulnerable and disaster-prone (fire, landslide, earthquake).
- **200 megawatts (MW) of solar and 400 megawatt-hours (MWh) of energy storage** will provide 100% protection to GLP against a complete transmission outage (“N-2 event”).
  - 200 MW of solar is equivalent to about 5 times the amount of solar currently deployed in the GLP and represents about 25% of the energy mix.
  - Multi-GWs of solar siting opportunity exists on commercial-scale built-environments like parking lots, parking structures, and rooftops; and 200 MW represents about 7% of the technical siting potential.
  - Other resources like energy efficiency, demand response, and offshore wind can significantly reduce solar+storage requirements.

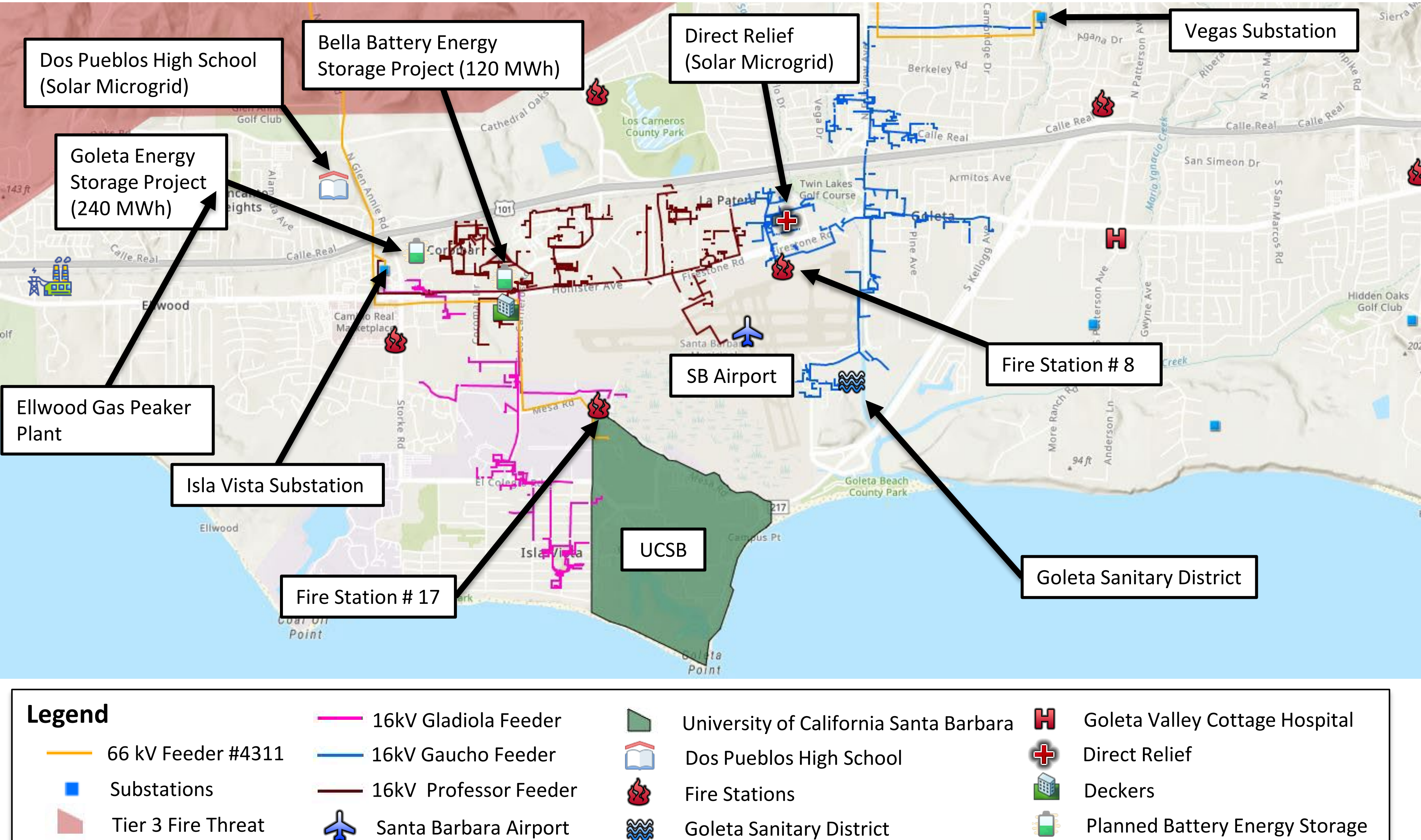
Core load area of the GLP

Clean Coalition



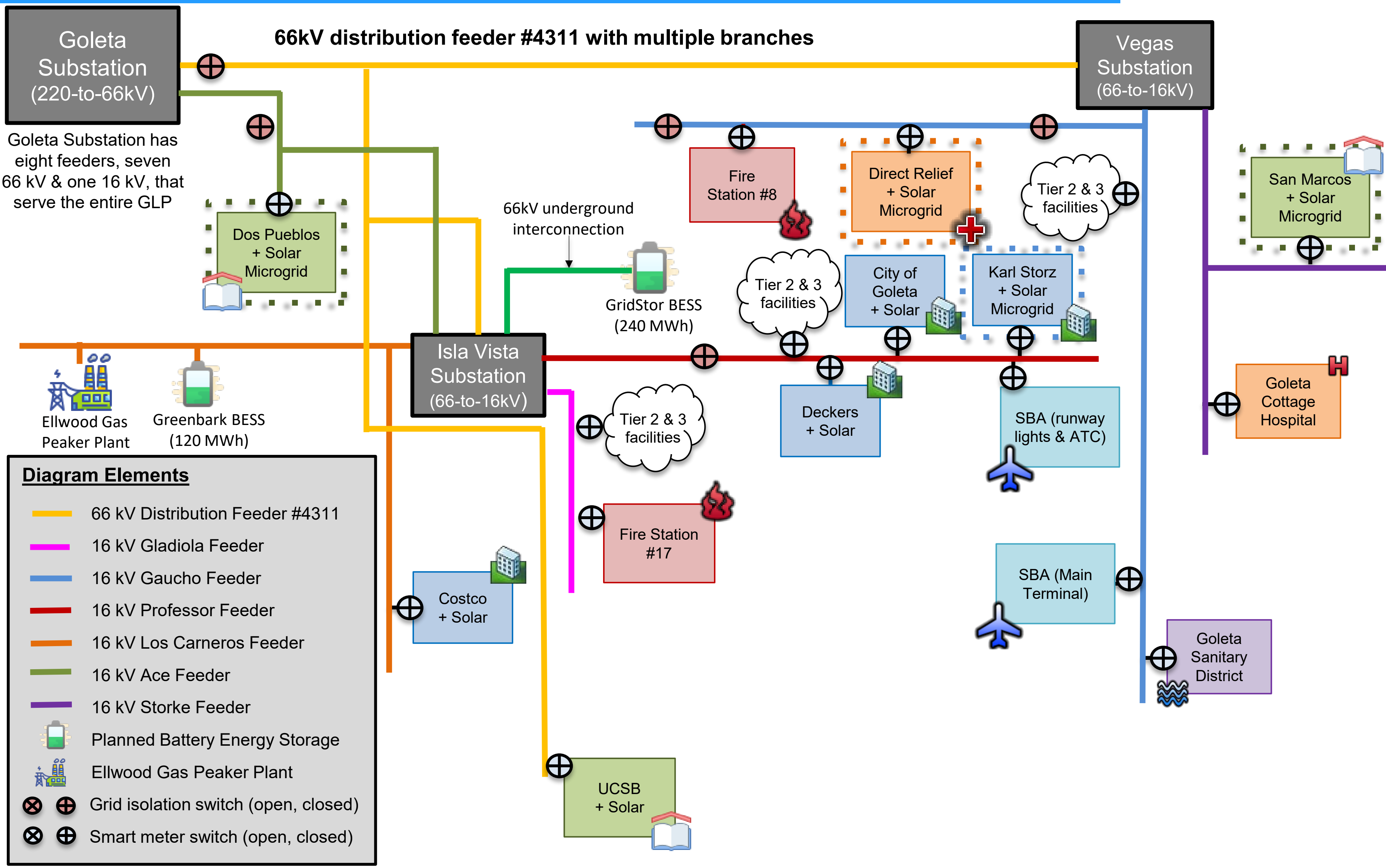
Target 66kV feeder serves critical GLP loads

Clean Coalition

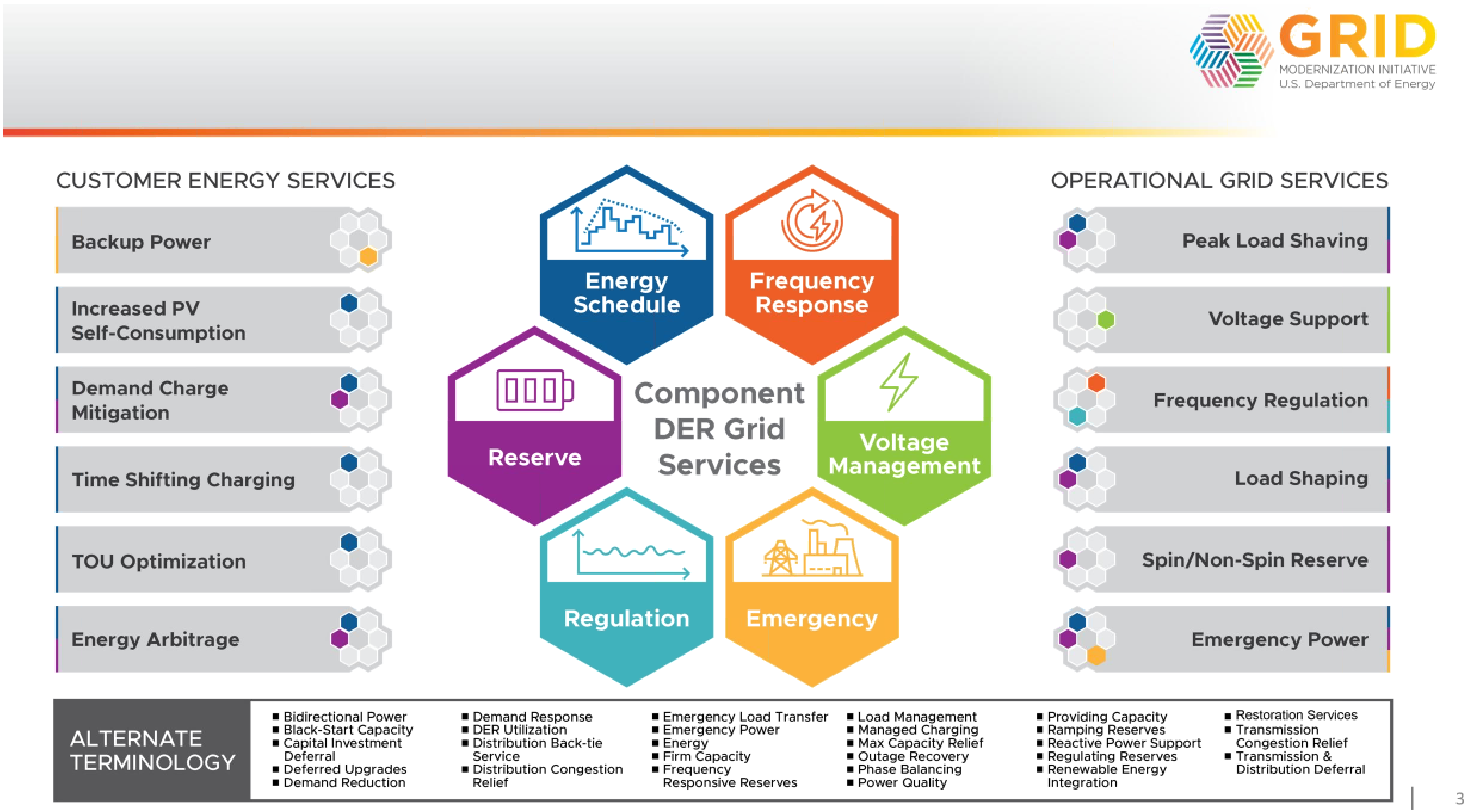


Target 66kV feeder grid area block diagram

Clean Coalition



Grid services that can be provided by DER



Spin/Non-Spin Reserve is likely not critical at the distribution level

Questions?

- Any questions?

- Email: ben@clean-coalition.org

CURRENT
ENERGY GROUP

Export Tariff Overview

California High DER Proceeding,

May 21, 2026

Andy Eiden, Sr. Manager

aeiden@currentenergy.group

Ron Nelson, Founding Partner

On behalf of Environmental Defense Fund

Overview

- Introduction and Background
- Export tariffs
- Achieving several regulatory goals for DER Orchestration
    - Planning
    - Price signals
    - Operations

About me…

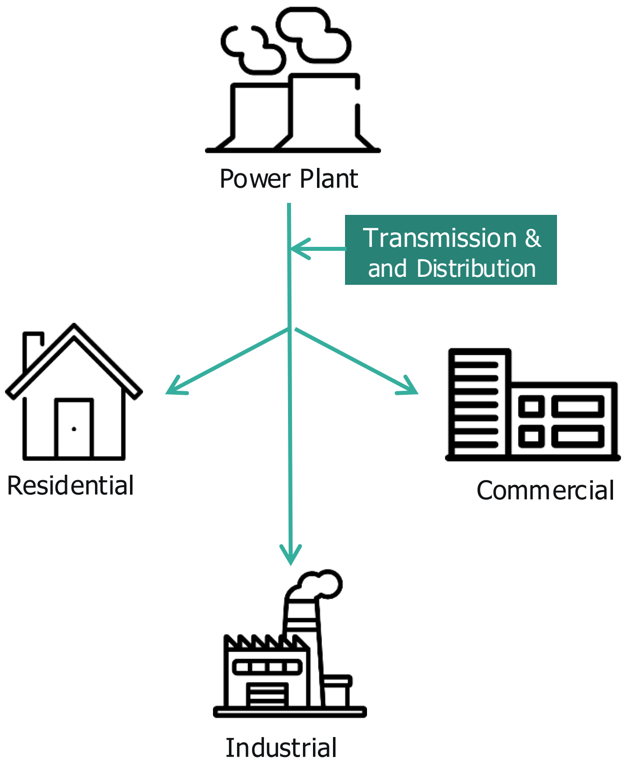
- Over 13 years experience across energy consulting, conservation program implementation, and utility sectors
- Prior to joining CEG, was lead DER planning analyst at Portland General Electric
  - Oversaw development of DER potential studies and responsible for integrating DERs into traditional distribution and transmission planning activities
- Co-authored paper on the need to evolve distribution capacity expansion planning (with NREL and Kevala).
- At CEG I've provided expert testimony in the following areas:
  - T&D rate cases
  - Utility system planning dockets related to DER forecasts and modeling
  - MA's Capital Investment Plans for proactive grid upgrades

Senior Manager in CEG's DER Integration and Advanced Rate Design + Cost of Service practices

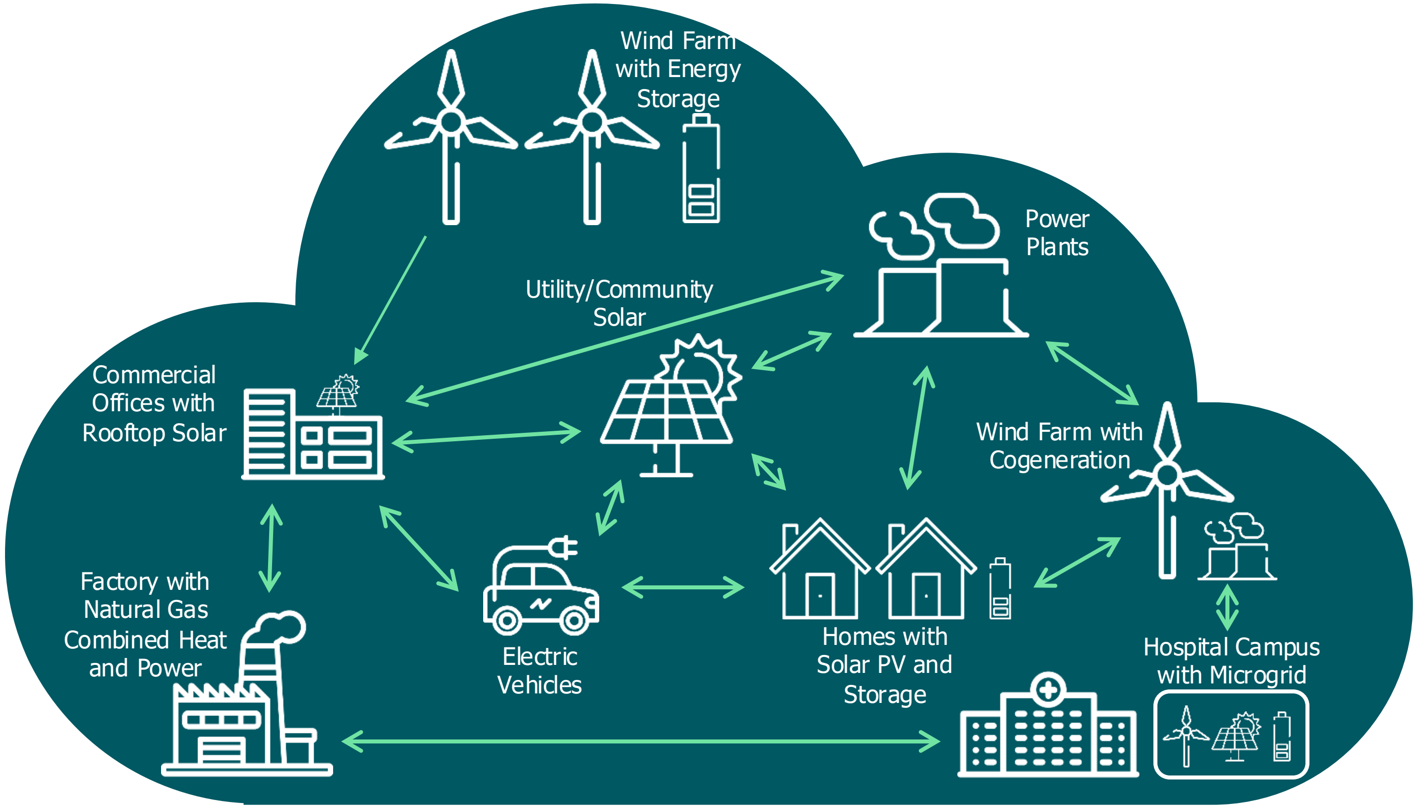
Introduction + Background

DER integration frameworks need to evolve to reflect a two-way electricity system

PAST: Traditional Power Grid
Central, One-Way Power System



TODAY: The Energy Transition
Distributed, Cleaner, Two-Way Power Flows



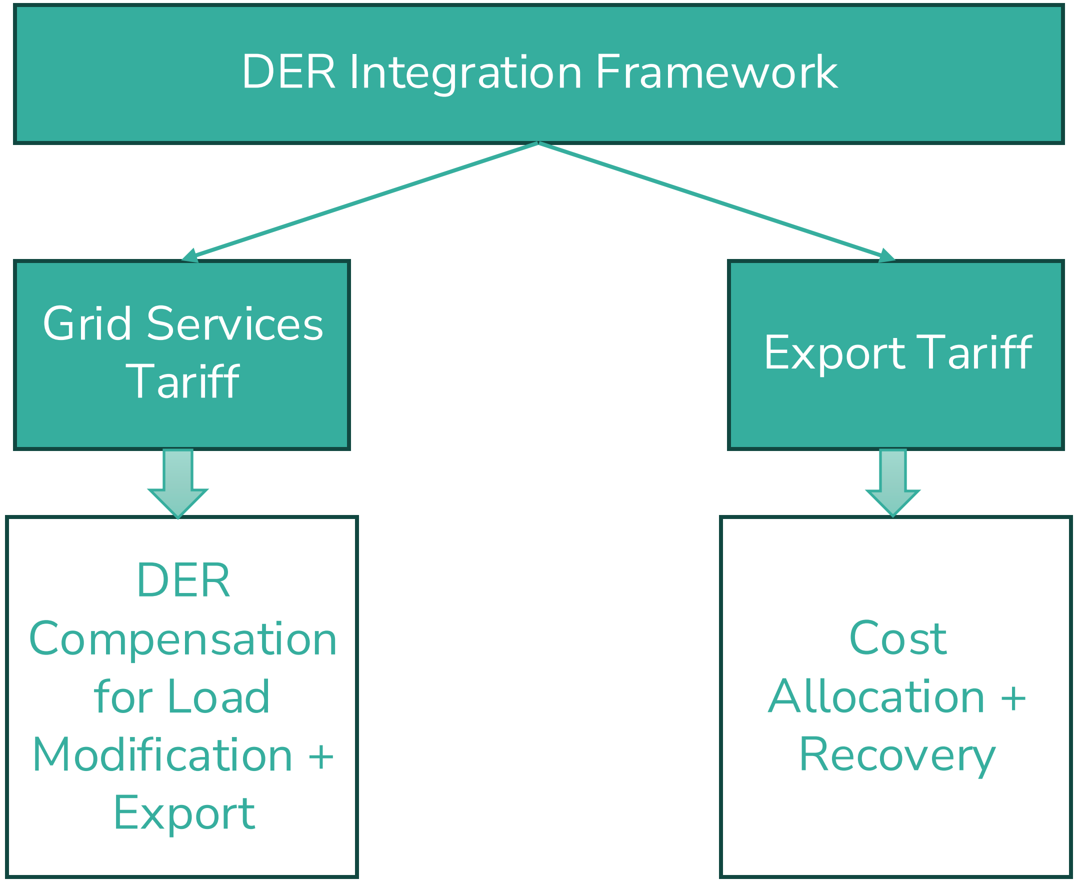
Advanced Rate Design for DER Orchestration

DER integration and bi-directional pricing should be considered collectively

Two primary elements to DER integration within ratemaking structure:

1. **Compensation** for services provided to the grid

2. **Allocation and recovery of costs** for interconnection and use of the grid for export



Source: https://emp.lbl.gov/publications/distributed-energy-resource-der

Export Tariff Framework

What is an Export Tariff?

- An **export tariff** is a contractual agreement for DER operating on the distribution system that enables **cost allocation and recovery** for export related impacts (e.g., capacity upgrades, new monitoring and control systems)
- **Align DER cost allocation with traditional ratemaking principles** and cost-of-service modeling
    - May implicate obligation to serve exporting customers
- **Reflect a bidirectional ratemaking structure** that services both import and export
- **Reduce cost and risk shifting within proactive upgrade frameworks** by spreading cost recovery over longer time periods and over a broader base of exporting facilities

Export Tariff Cost Allocation

Conceptual Framework

Align the treatment of exporting DER facilities with how importing load facilities are treated today

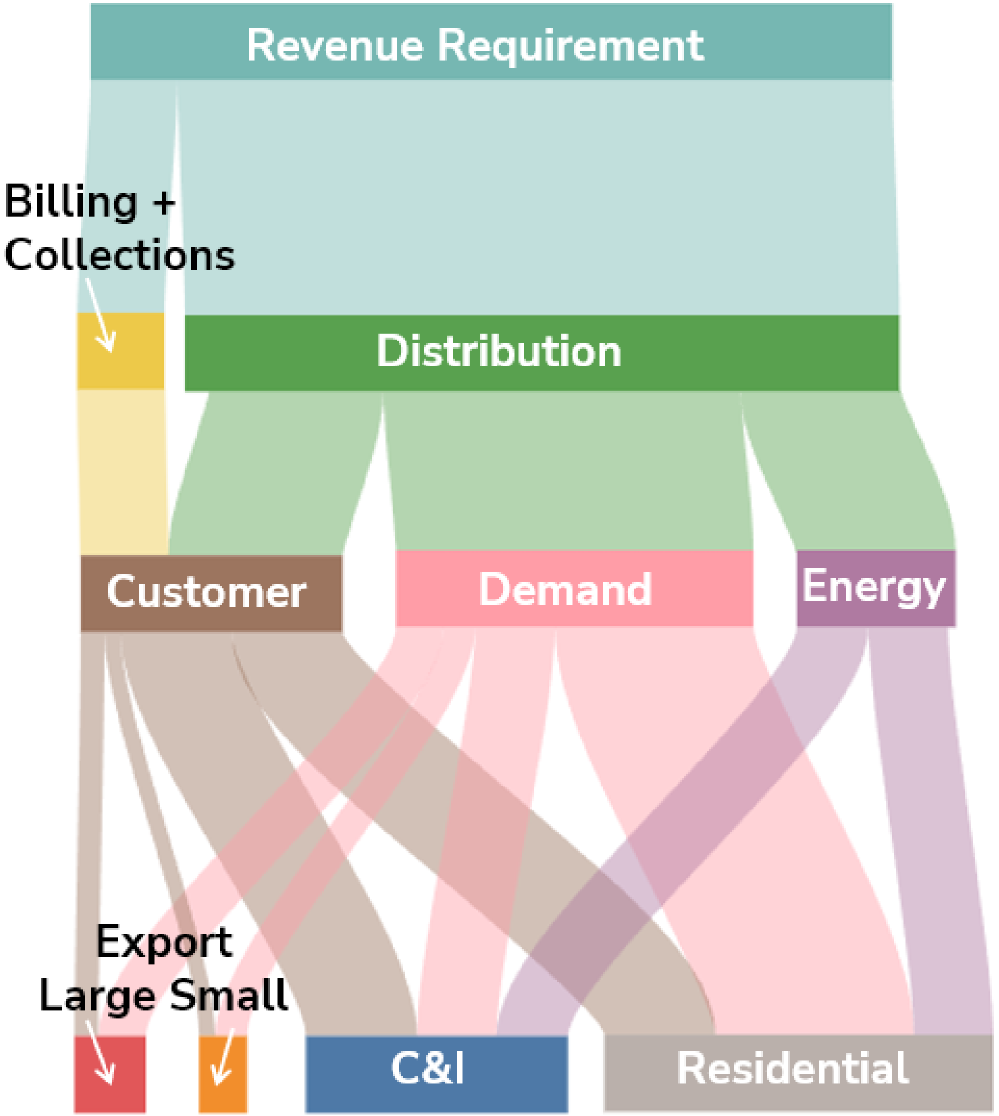
Recognize export as a utility service, not simply a cost at interconnection

Utilities consider DER interconnection within the annual distribution system planning (DSP) process, where they are provided cost recovery for prudent upgrades that are needed to accommodate export

All exporters are allocated costs and charged based on their use of the system for exporting energy, using the same cost allocation principles as load.

Cost Allocation

- Cost allocation and recovery differs significantly for load and export
- Applying ratemaking principles can more equitably and efficiently connection export
- Flexible connections can allow less costly connections for export, but price signals are needed that do not currently exist



Graphic adapted from Regulatory Assistance Project (2020). Electric Cost Allocation for a New Era: A Manual, Figure 20 and 21.

Export Tariff Example

Conceptual Framework

	Applicable time	Consumption Charge	Export Reward/Charge
Peak import period	2pm - 8pm everyday	Peak charge 25.37 c/kWh	Reward equal to -25.37 c/kWh
Solar soak period	10am-2pm everyday	Off-peak charge 3.77 c/kWh	Off-peak charge 1.85 c/kWh
Off-peak	8pm to 10am everyday	Off-peak charge 3.77 c/kWh	
Fixed charge		Fixed charge 48.72 c/day	

Bi-directional Planning and Forecasts

Export tariffs can create an obligation for utilities to integrate export requirements into “traditional” processes

Export tariffs can provide price signals to incentivize flexible connections that can be integrated into forecasting and planning

Increased focus on co-optimization and prioritization

Align utility incentives with improving export services

+ Utilities earn returns on rate-based investments to improve export capability

The current framework provides no incentive to the utility to expand hosting capacity when customers fund hosting capacity upgrades at interconnection.

→ Export Tariffs provide utilities a return for planned infrastructure hosting capacity investments which become part of the utility's rate base.

+ Utilities receive revenue from exporters

Under current cost allocation utilities can lose revenue from DER that provide grid services.

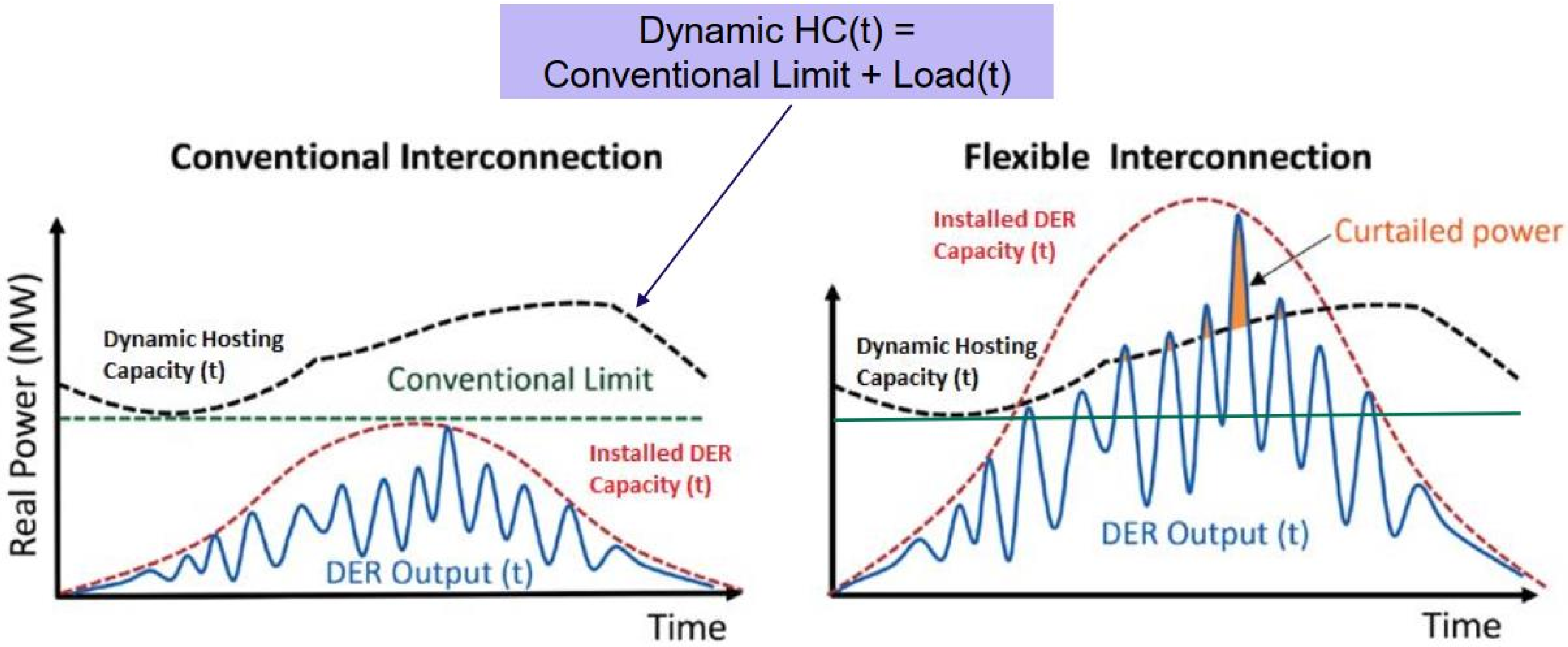
→ Export Tariffs create continued revenue from exporters, as exporting DER pay recurring fees based on their ongoing use of the grid to export.

+ Utilities receive prudency review of their system plans

Current cost allocation provides little oversight of DER interconnection upgrades and cost impacts.

→ Export Tariffs integrate hosting capacity upgrades into the system planning process. Utilities demonstrate prudent investment to receive recovery.

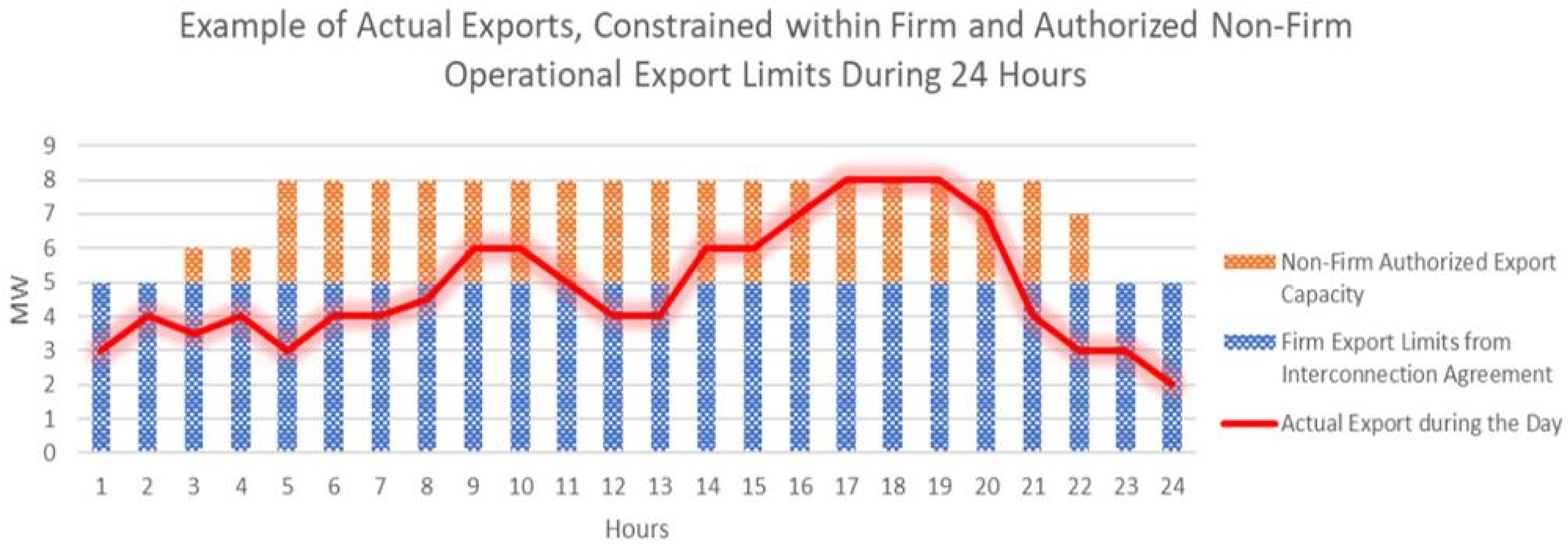
Flexible Interconnection



- The CPUC has already recognized that flexible connections can greatly increase the utilization of the distribution network for both load and export
- To scale flexible connections, certainty around potential curtailment is needed as well as service options for customers outside of constrained areas. Export tariffs are a vehicle to evolve the Limited Generation Profiles ordered by the Commission

Graphic reference: EPRI Understanding Flexible Interconnections

Firm and Non-Firm Tariffs



- Export and grid services tariffs can create a paradigm with firm and non-firm rate options
- This would support the ongoing work in the High DER proceeding on dynamic flexible service connections by appropriately compensating flexible load and generation

Graphic reference: [EPRI Understanding Flexible Interconnections]

Closing Thoughts

- Export tariffs can be integrated into all aspects of ratemaking and function symmetrically to load rates to support DER Orchestration
  - Export tariffs provide vehicle to address all associated cost allocation and recovery issues with exporting facilities as opposed to creating several custom-made processes that compound regulatory complexity
- Adopting export tariffs + grid services tariffs can be a mechanism to better align costs and revenue over time, leading to greater rate stability and certainty enshrined in traditional cost of service ratemaking principles
- Aligning utility incentives with policy outcomes related to DER orchestration can help scale deployment in a cost-effective, technology neutral manner

CURRENT
ENERGY GROUP

Shaping the Path Forward

Thank you

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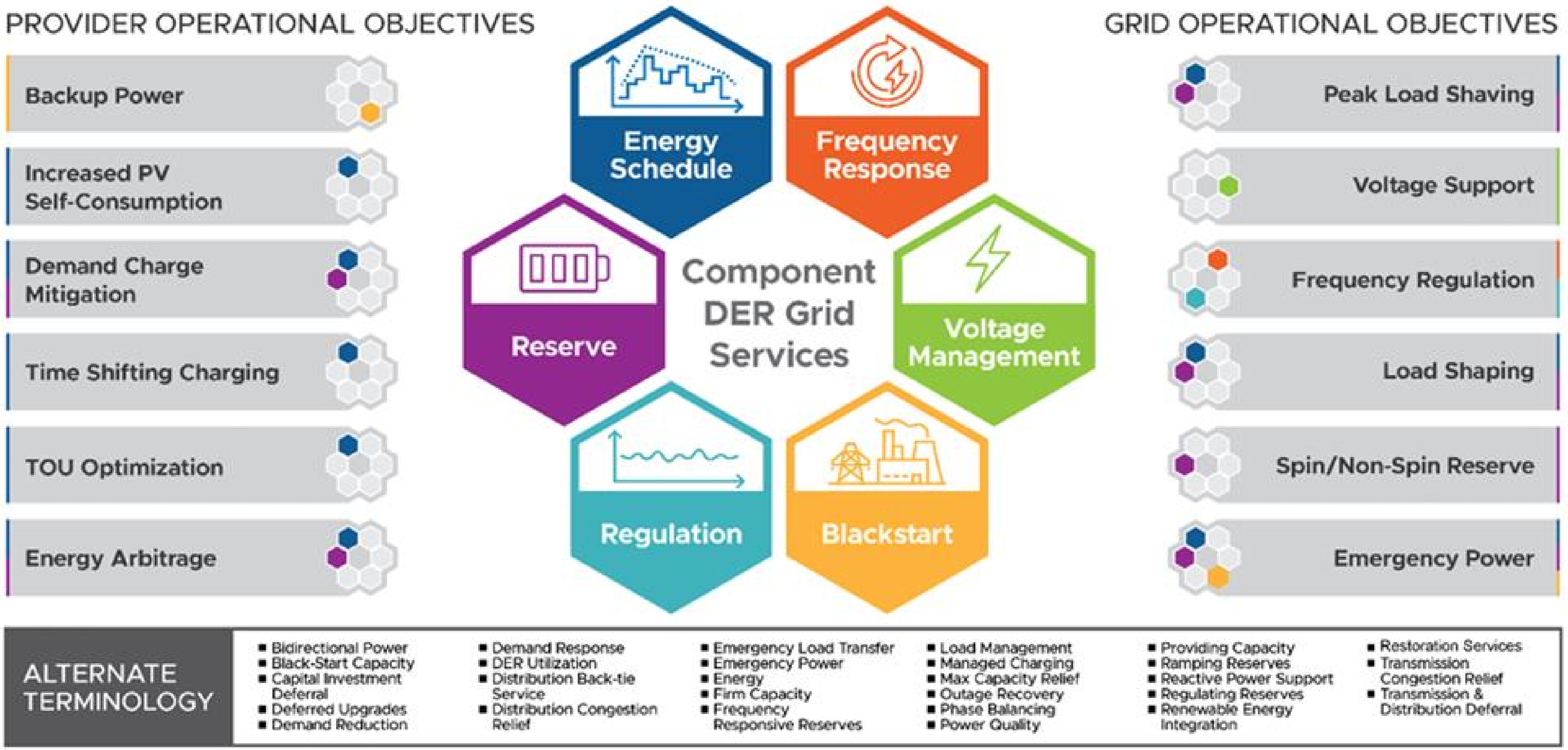
Standard Grid Service Definitions

Common terms and definitions of grid services support standardization at grid edge



Source: PNNL (2023). "Common Grid Services Terms and Definitions Report."

NuCore

The Missing Layer: Why DER Orchestration Requires a BTM Platform

CPUC Workshop : May 21, 2026 • R.21-06-017 • Universal Devices

Everything described is already built, deployed, and available on GitHub.

Who We Are

20+

Years Deploying Energy Management and Demand Response Systems

Real-world production systems
OpenADR 2.0a/2.0b/3.0 Certified

100K+

Systems In the Field

Real homes · Real devices · Real Utility Integrations

Now

Code on GitHub Today

Not a roadmap; already running

Active PG&E & SCE Projects

CEC Grants: Foundation for CalFuse
3 Comment filings: Apr 3 (Track 3), Apr 17 (Track 1&2 Opening), Apr 29 (Reply)

Not a vendor pitch

We are here because we have seen this problem from the ground up.

Structural concern

The current trajectory has flaws that will be expensive to correct later.

DER Orchestration Requires Three Layers

The ACR addresses Layer 1 comprehensively and Layer 2 partially. Layer 3 is absent from every party's filing.

LAYER 1
DSO Signal Layer

IOU ADMS/DERMS
Visibility, forecasting, dispatch to point of interconnection

✓ ACR addresses this layer

LAYER 2
Aggregation Layer

Aggregators or direct platform enrollment
Fleet dispatch, demand response, VPP enrollment

~ ACR addresses partially

LAYER 3
BTM Execution Layer

Device-level translation and execution at customer premises
Thermostats, EVSEs, inverters, panels, pool pumps — all protocols

✗ NOT ADDRESSED by any party

NuCore spans Layer 2 and Layer 3 — the only platform that covers both.

Layer 3 Is the Gap No Other Party Has Filled

What Other Parties Address

CALSSA: Batteries and EVs managed by aggregators

Nexamp: Solar and storage projects

PG&E / SCE: Primary-feeder ADMS/DERMS deployment

CAISO: Bulk system visibility

The Council: Competitive market access

No party disputes the gap exists. None proposes a solution.

The Unaddressed Gap

Millions of thermostats, legacy EV chargers, smart panels, pool pumps, and water heaters already in California homes.

Capable of demand flexibility today. Communicate via Z-Wave, Zigbee, Wi-Fi, Modbus, proprietary APIs.

IOU DERMS does not reach them. No aggregator serves them at scale. No standard addresses them retroactively.

This is the largest untapped demand flexibility resource in California.

$42B

in projected California grid upgrade costs through 2040 without demand flexibility

Source: IOU Electrification Impact Study Part 2, cited in CALSSA Opening Comments Apr 17, 2026

7-10%

estimated cost reduction under current program assumptions — far below what residential BTM can deliver

The Residential BTM Installed Base Is the Largest Untapped Demand Flexibility Resource in California

No Opening Comment filed by any party addressed the residential BTM installed base. None disputed the gap. None proposed a mechanism to reach it.

A DER orchestration framework that does not reach the residential BTM installed base will not achieve the ratepayer savings that justify the framework's costs.

Gap Detail: BTM Devices & Standards Risk

GAP 1

Existing BTM Devices Are Completely Unaddressed

Millions of thermostats, inverters, EV chargers, and load controllers are already installed in California homes.

No bridging solution was even mentioned. Without an on-ramp for existing devices, 2030 targets
will not be achievable at scale.

GAP 2

Standards Built on Unfinished Foundations

AMI 2.0 is cited throughout R.21-06-017 but not defined with sufficient specificity to build against.

Matter for DER EVSE added in v1.3 (May 2024). As of Oct 2025, exactly one certified EVSE product exists: a niche RV battery controller. Matter-native battery storage: zero production devices. The risk is already materializing.

GAP 3

Framework Is Fragile to Policy Change

Optimized for VOE, but what if VOE is superseded by something else? Without insulation of implementation from policy shifts, we'll remain in perpetual cycles of defining standards.

GAP 4

No Answer to Manufacturer Adoption

The proceeding implicitly assumes manufacturers will abandon deployed protocols (CSIP, SunSpec, proprietary backends) and pivot to Matter. Not a transition plan; an expectation without a mechanism. At the Feb 20, 2026 Track 3 workshop, SCE confirmed it uses an Australian CSIP variant because standard CSIP lacks export limits. The fragmentation is current.

Gap 5: The Aggregator Focus Adds Additional Costs

CURRENT MODEL	NUCORE MODEL
Utility	Utility
▼	▼
Aggregator ← toll booth	**Behind-the-Meter Platform ← direct signal**
▼	▼
OEM	Customer Devices
▼	▼
Customer Device	Aggregator (optional) ← value-added, not mandatory

Concentrating market power in a small number of aggregators is exactly the monopoly risk the Commission has a mandate to prevent. At the Feb 20, 2026 Track 3 workshop, PG&E confirmed its aggregator interface is currently proprietary and non-standardized: an open interface is "under development." The toll booth is not hypothetical; it is the current state.

The Aggregator Debate Is About Layer 2, Not Layer 3

CALSSA, UCAN, 350 Bay Area frame the choice as: aggregators control devices OR utilities control devices. Both miss the point.

The Aggregator vs. Utility Debate

Layer 2 — Aggregation

Who dispatches the fleet? Who sends the grid signal to aggregated assets?

Universal Devices does not dispute CALSSA on aggregator capabilities. Aggregators are good at fleet dispatch.

The dispute is with the framing, not the facts.

What the Debate Leaves Unresolved

Layer 3 | BTM Execution

An aggregator sends a signal to its enrolled devices. It does not control each device directly, device-level software translates that signal into a device-specific command.

For the heterogeneous residential BTM installed base, no aggregator provides that translation layer at scale.

Communication Protocol Concerns

CALSSA

California should not mandate one standard. If there are other pathways already implemented or lower-cost, we should not preclude them.

UCAN

Opposes forced IEEE 2030.5 at device level, since it locks out OpenADR-based aggregators unnecessarily, creating IT bottlenecks and driving up compliance costs.

350 Bay Area

Supports OpenADR and existing internet-based protocols. Opposes proprietary communications requirements that exclude deployed devices.

Nexamp

Supports a protocol strategy that identifies the proposed stack and explains how IEEE 2030.5 or OpenADR will integrate systems at scale.

Question: Why not let each utility decide what's best for its use cases at the DSO layer?

Standards Change, But Platforms Endure!

Millions of apps exist. Each one follows its own logic, its own updates, its own rules. But your phone doesn't care; when an app changes, you update it. When a better app comes along, you swap it.

The phone keeps working. The platform (iOS/Android) never had to know what BofA or Tesla would do. It just had to make sure anything built for the platform could plug in and run.

01 Device Discovery & Integration

Including legacy and non-compliant devices: the installed base that standards will never retroactively reach

02 Protocol Translation & Bridging

Across generations of hardware and evolving standards, without requiring device replacement

03 Local Intelligence & Resilience

The system must function when aggregators go out of business or cloud connectivity fails

04 Policy Adaptability

VOE today, XYZ tomorrow: the platform adapts; deployed devices are untouched

NuCore Platform

Open Source

All Universal Devices source code donated. Available on GitHub now and running on deployed hardware today.

Non-Profit Governed

No single vendor controls it. Designed to be California's infrastructure; not a product.

Plugin Architecture

Enables mass device/standards support, mass adoption, and enables workforce development.

Policy Agnostic

VOE today, something else tomorrow , control logic adapts without a platform rebuild.

Customer-Focused

Platform relationship is between customer, their devices, their utility, and preferences.
Aggregators exist as value-added services.

1,000s of Device Types

Native support for off-the-shelf and legacy BTM devices no current standard addresses.

NuCore Spans Both the Missing Layers

DSO Signal
Utility Specific Protocol

DSO Signal Plugin

NuCore

Layer 2 + Layer 3
Policy engine + device execution

At Layer 2: Direct DSO enrollment via utility's protocol of choice with OpenADR and 2030.5 being the minimal requirements.

At Layer 3: Translates signal into device-native commands: Matter, Z-Wave, Zigbee, Wi-Fi, Modbus, SunSpec, proprietary APIs

Edge Resilience: Functions during wildfires when cloud and cellular fail; exactly when flexibility is most critical

Policy-Agnostic: VOE today, dynamic envelopes tomorrow, VPP next year. Deployed devices are untouched when policy changes.

No aggregator product spans both layers. This dual-layer capability is what makes NuCore a platform rather than a point solution.

A Statewide Framework Is the Right Answer

Advanced Energy United argues the Commission must define the framework before IOU applications. Universal Devices agrees and applies this logic most forcefully to the BTM execution layer.

Without Commission-Level Standards

PG&E: Flex Connect on primary feeders
SCE: Bridging approach only; everything else conceptual
SDG&E: No near-term standardized offering

Result: Three incompatible residential BTM environments. Device manufacturers and aggregators face three integrations. Customers who move territories find BTM platforms inoperable.

What the Commission Should Define

Formally recognize the BTM execution layer as foundational infrastructure; not optional, not IOU-specific.

Define minimum functional specifications: protocol neutrality, edge operability, open interfaces, device discovery and translation.

Require each IOU application to demonstrate how its framework addresses that layer before filing.

NuCore is available as the reference implementation against which those specifications can be evaluated.

The Ask

1

Minimum Requirement of OpenADR and IEEE 2030.5 at DSO Interface.

Mandate IOU applications to support OpenADR and IEEE 2030.5 at the DSO interface, while preserving the flexibility for proprietary variations.

2

Formally Recognize the BTM Execution Layer

Recognize the BTM execution layer as a distinct, foundational infrastructure component. Define minimum functional specifications – DSO interface minimum protocol support, edge operability, open interfaces, device discovery and translation – at the Commission level before IOU applications are filed.

3

Designate NuCore as Reference Implementation & Require Benefit-Cost Transparency

Propose NuCore as the reference implementation for the residential and secondary BTM layer. The use case no IOU has addressed. Require that benefit-cost analyses include aggregator transaction costs as an explicit line item. Require open, published DSO aggregator interfaces on a defined timeline.

Q/A

Q How is this different from OpenADR or IEEE 2030.5?

Those are signal and communication standards — they define the message. NuCore is the system that receives the message, interprets it, and executes it on 1000+ real devices. Complementary, not competing. This position is now on the R.21-06-017 record: CalCCA explicitly argued at the Feb 20, 2026 Track 3 workshop that OpenADR and IEEE 2030.5 are complementary, not either/or.

Q Why non-profit? Why not a commercial product?

California's grid infrastructure cannot depend on a single vendor's commercial decisions. Non-profit governance ensures the platform remains neutral, open, and persistent regardless of any one company's fate.

Q What is the governance model?

We are actively developing the non-profit structure and are open to CPUC input on governance to ensure it aligns with the Commission's neutrality and public interest requirements.

Q Are you saying aggregators have no role?

Not at all. Aggregators can and should exist as value-added services, for customers who want them. What we oppose is aggregation that introduces fees and market concentration working against Commission objectives.

NuCore

Open Source · Non-Profit Governed · Running Today

Universal Devices : https://universal-devices.com
NuCore : https://nucore.ai
GitHub : https://github.com/NuCoreAI

R.21-06-017 · CPUC Distributed Energy Resource Framework

Michel Kohanim – michel@universal-devices.com
Orly Hasidim – orly@universal-devices.com

CAISO Demand Flexibility Strategy - Vision & Pillars

Vision

A future where demand flexibility is reliably and economically integrated into grid operations and market optimization

Operational Coordination Framework

Strengthens coordination and situational awareness for market and non-market demand and supply by enhancing data visibility and forecasting capabilities.

Technology & Data Exchange

Define and develop the technology and data exchange requirements necessary to support the Coordination Framework with automated exchange of a common set of information.

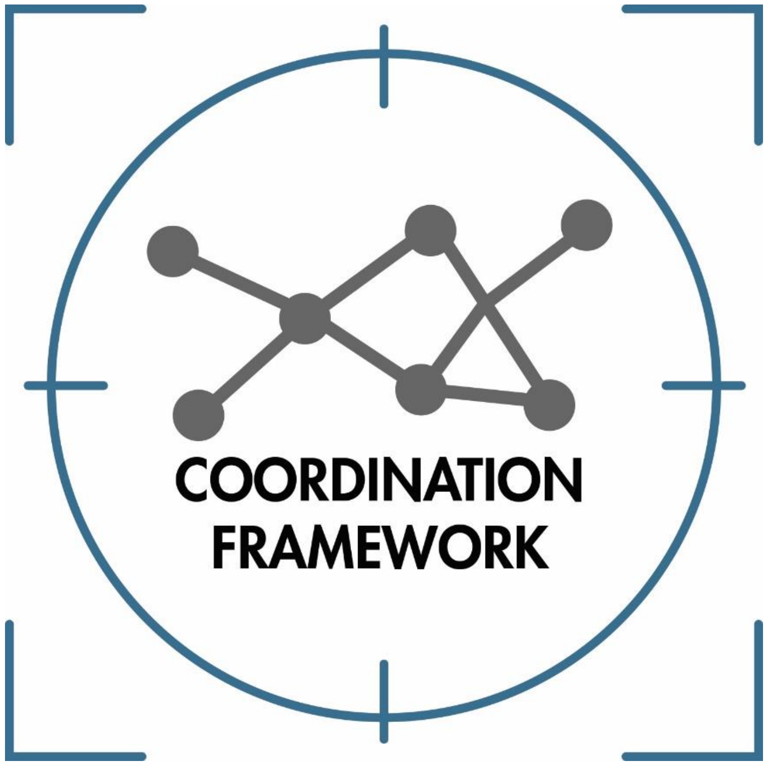
Market Design

Develops and enhances pathways to market access – both on the supply and demand-side

Policy & Regulatory Alignment

Collaborates with regulatory partners to identify and address barriers

Focus areas of coordination framework



- Enhanced Operational Coordination
- Information and Visibility
- Operational Forecasting

From Challenges to Future Opportunities

ACTIONS

Enhance DER Visibility

- Improve forecasting to reduce uncertainty in market operations
- Strengthen situational awareness
- Integrate DER data into system planning

Leverage DER Dispatch Data

- Use dispatch information to improve emergency response and coordination
- Optimize market performance by aligning DER operations with system needs

Capture Untapped Demand Flexibility

- Enable new resources (large loads) and new sources of value
- Enhance reliability while reducing costs through flexible load participation
- Defer or avoid costly infrastructure investments by substituting DER flexibility for new build-outs

RESULTS

Reduce Uncertainty and Strengthen Reliability

Optimize Coordination and Market Outcomes

Enable Market Value and Defer Infrastructure