BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future.	Rulemaking 21-06-017 Filed June 24, 2021

CLEAN COALITION COMMENTS ON ASSIGNED COMMISSIONER'S AND ADMINISTRATIVE LAW JUDGE'S RULING ISSUING QUESTIONS ON THE DISTRIBUTED ENERGY RESOURCES ORCHESTRATION WORKSHOP REPORTS

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I. INTRODUCTION

Pursuant to the Rules of Practice and Procedure of the California Public Utilities Commission ("the Commission"), the Clean Coalition respectfully submits these comments on the *Assigned Commissioner's and Administrative Law Judge's Ruling Issuing Questions on the Distributed Energy Resources Orchestration Workshop Reports*, issued by the Commission on July 9, 2026.

The workshop reports demonstrate broad agreement that DER orchestration can improve utilization of the distribution system, accelerate energization, avoid or defer infrastructure, and enable DER to provide reliable grid services. They also confirm, however, that foundational questions concerning market governance, valuation, interoperability, data access, utility readiness, and the roles of CCAs and third-party providers remain unresolved. Those questions should not be answered independently through three utility-specific applications. The Commission should first establish a common statewide architecture and then require IOU applications, pilots, and phased implementation to operate within it.

Clean Coalition recommends that the Commission:

- Establish the governing DER orchestration framework before directing IOU applications (Questions 2, 4, 5, 6, 7, and 18)
- Require a local-first DSO that uses open-access and competitively neutral markets (Questions 2, 5, 6, 7, 9, 17, and 18)
- Identify the full DER value stack and adopt a transparent and bankable valuation framework that reflects local and temporal value, preserves legitimate value stacking, and compares DER portfolios with infrastructure on an equivalent basis (Questions 2, 5, 7, 14, 16, and 18)

- Require the framework to value resilience and enable Community Microgrids (Questions 2, 5, 7, 16, 17, and 18)
- Require layered and interoperable DERMS that enable CCA and third-party participation (Questions 2, 5, 7, 10, 11, 13, 16, and 18)
- Use pilots to accelerate implementation and scaling, not defer foundational decisions (Questions 3, 4, 5, 7, 10, 15, 17, and 18)
- Convene a time-limited working group and promptly adopt a statewide regulatory framework.

II. DESCRIPTION OF PARTY

The Clean Coalition is a nonprofit organization whose mission is to accelerate the transition to renewable energy and a modern grid through technical, policy, and project development expertise. The Clean Coalition drives policy innovation to remove barriers to procurement and interconnection of DER—such as local renewables, demand response, and energy storage—and we establish market mechanisms that realize the full potential of integrating these solutions for optimized economic, environmental, and resilience benefits. The Clean Coalition also collaborates with utilities, municipalities, property owners, and other stakeholders to create near-term deployment opportunities that prove the unparalleled benefits of local renewables and other DER.

III. COMMENTS

A. Question 1: Clarifications to the workshop reports

The workshop reports generally provide an accurate summary of Clean Coalition's presentation. However, the description should be clarified to reflect that Clean Coalition proposed an integrated local-first framework that included open-access market mechanisms, coordination between grid-level and third-party or CCA edge DERMS, compensation of the full locational value stack, and explicit recognition of resilience and Community Microgrid-enabling services. Clean Coalition also presented the Goleta Load Pocket as a concrete example of a transmission-vulnerable area where coordinated DER deployment could provide substantial local reliability and resilience benefits. In addition, Clean Coalition emphasized that DSO financial incentives should be aligned with speedy interconnection, timely energization, efficient DER operation, and avoided infrastructure costs.

B. The Commission should establish the governing DER orchestration framework before directing IOU applications (Questions 2, 4, 5, 6, 7, and 18)

The Commission should establish the governing architecture for DER orchestration before directing the IOUs to file utility-specific applications. The workshop record demonstrates broad interest in DER orchestration, but it also confirms that foundational questions concerning market structure, valuation, governance, interoperability, utility readiness, and the roles of Community Choice Aggregators ("CCAs") and third-party aggregators remain unresolved. The Commission should not allow those questions to be answered for the first time through IOU applications.

At a minimum, the Commission should first establish statewide requirements governing:

- open and nondiscriminatory market access,
- the respective roles of the DSO, aggregators, CCAs, and market administrators,
- common grid-service products and definitions,
- interoperability and data-access requirements,
- valuation and value-stacking principles,
- performance, settlement, and verification standards,
- safeguards against utility self-preference, and
- criteria for comparing DER portfolios against traditional infrastructure.

Responsibility for safe and reliable distribution operation does not require IOU control over every commercial function of the distribution market. The DSO may identify grid needs, establish operating envelopes, define reliability constraints, and verify performance while an independent or competitively neutral platform administers registration, procurement, dispatch communications, and settlement. The Commission should therefore evaluate independent market administration alongside IOU-operated marketplaces rather than assume that the IOU's operational responsibilities require exclusive control over market access.

The workshop record supports further consideration of this structure. SDG&E supported open access and transparent procurement in which qualified providers may compete, CalCCA urged consideration of independent marketplace operators before granting utilities exclusive dispatch authority, and Clean Coalition continues to support transparent marketplaces using third-party aggregators. The report also identifies independent marketplace operators and alternative governance models as unresolved issues requiring further development.

Open access must mean more than allowing aggregators to participate in an IOU-designed program. A workable open-access market requires published grid needs and eligibility rules, common statewide products, transparent pricing or competitive procurement, nondiscriminatory access to relevant data, interoperable communications, neutral settlement and performance rules, independent oversight or dispute resolution, and protections against utility self-preference. The Commission need not resolve every implementation detail before applications are filed. However, it should establish the foundational policy and market rules first so that IOU applications implement a common statewide framework rather than define three separate and potentially incompatible markets. The statewide framework should also align IOU incentives and performance evaluation with successful DER integration. A DSO should be evaluated on outcomes such as avoided or deferred infrastructure costs, improved utilization of existing assets, faster interconnection and energization, increased DER participation, reliable delivery of procured services, and reduced total system costs. Without corresponding performance metrics and accountability, the IOU may remain financially better positioned to pursue conventional capital investment even where an orchestrated DER portfolio can meet the same need at lower total cost. Utility-specific applications should demonstrate compliance with the adopted framework, identify incremental capabilities and costs, and explain how the proposal will support open participation, bankable DER compensation, and measurable ratepayer benefits.

C. The Commission should require a local-first DSO that uses open-access and competitively neutral markets (Questions 2, 5, 6, 7, 9, 17, and 18)

Maximizing the ratepayer savings available from DER orchestration requires a market designed to reduce barriers to entry and allow a broad range of distributed technologies and aggregations to compete. Competition should be organized around the location, timing, duration, and performance characteristics of the identified grid need rather than a utility-preferred technology or program design.

For example, Piclo's flexibility market model allows DER providers to bid capacity capable of operating during the time window and at the location needed by the grid. By procuring the required service rather than prescribing a specific technology, this approach allows individual resources, hybrid configurations, and aggregated portfolios to compete on equal terms.[1] Technology-neutral procurement can reveal lower-cost solutions while allowing DERs to combine distribution-market revenues with other compatible value streams needed to support bankable investment. This should include value streams that become fully realizable only as additional resources or capabilities are assembled, provided the resource is already creating a distinct and measurable component of that future value.

A local-first operating objective will produce meaningful savings only if the DSO can obtain the most cost-effective local solution through an open and competitive market. *The Commission should apply this principle through common statewide market rules, transparent publication of grid needs, objective eligibility and performance requirements, and nondiscriminatory access for CCAs, aggregators, and other qualified providers.* Open access should not mean merely allowing third parties to participate in an IOU-designed program on terms established through utility discretion. It should create a durable market in which qualified resources can identify opportunities, compete to provide defined services, and receive compensation based on the value delivered.

This local-first framework also provides the appropriate approach to PG&E's identified use cases of system peak reduction, speed-to-power, and resource-efficient grid investments. All three are valid and should generally be pursued in parallel rather than through separate or sequential programs. The DSO should determine whether new load, local constraints, or upstream needs can be addressed through local generation, storage, flexible load, operating envelopes, or other DER services before defaulting to additional upstream supply or traditional infrastructure. Remaining net imports, exports, and bulk-system requirements should then be coordinated at the T-D interface.

Initial implementation should be targeted to locations where needs are already identifiable and the potential benefits are greatest, including constrained circuits and substations, persistent load pockets, areas experiencing energization delays, and locations facing substantial planned infrastructure investment. The same local DER portfolio may accelerate energization, reduce local and coincident system peaks, and avoid or defer infrastructure, allowing the three use cases to reinforce rather than compete with one another.

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[1] Track 2 Workshop Report: TSO-DSO Coordination, at p. 12.

D. The Commission should adopt a transparent and bankable framework for the full DER value stack (Questions 2, 5, 7, 14, 16, and 18)

The report identifies value stacking as necessary for economic viability and explains that marketplace coordination can prevent genuine double counting without eliminating multiple legitimate revenue streams. The Commission should adopt four principles when developing a complete DER value stack:

1. Value should be local and temporal.
2. Distinct services should remain stackable.
3. Compensation must be bankable.
4. Valuation should compare DER portfolios against infrastructure on an equivalent basis.

Establishing these principles in advance will ensure that IOU applications use a common valuation architecture rather than proposing inconsistent approaches to the same grid services.

i. Value should be local and temporal

The Commission has long recognized that DER can avoid system costs and produce savings for ratepayers. The Avoided Cost Calculator ("ACC") provides a system-level framework for quantifying many of those avoided costs and informs DER valuation and compensation in programs such as the Net Billing Tariff ("NBT"). However, where the need is circuit- or substation-specific, system-average ACC values are insufficient. The value assigned through a DSO framework must reflect:

- the specific constraint;
- avoided or deferred project cost;
- timing and duration;
- probability of need;
- operational alternatives;
- and effects on upstream transmission requirements.

The resulting locational value must also be transparent and actionable. Prospective resource owners and aggregators should be able to identify, before applying, where needs exist, the services required, the relevant performance window, the anticipated duration of the need, and the methodology that will be used to determine compensation. Without a clear ex ante indication of potential local value, participation will remain dependent on case-by-case utility inquiries, increasing transaction costs and limiting competition.

ii. Distinct services should remain stackable

Preventing double compensation is an important consideration, but it should not become an excuse to erase legitimate, distinct value streams. Clean Coalition urges the Commission to adopt clear rules so that the IOUs and market participants apply this principle consistently. The distinction is between:

- double payment for the same capacity commitment during the same period, and
- separate compensation for separate services, availability periods, performance obligations, or beneficiaries.

For example, a battery might legitimately receive compensation for local capacity deferral, voltage support, resilience readiness, and bulk-system services, provided its obligations are compatible and the same capacity or performance capability is not committed twice.

This principle is consistent with PG&E's description of a DSO as supporting "the responsible stacking of multiple grid services from the same DERs" and overcoming fragmentation across existing program silos.[2] The workshop record also recognizes that marketplace platforms can support multiple revenue streams while coordinating commitments and monitoring performance to prevent genuine double counting.[3]

The Commission should therefore establish statewide rules that distinguish incompatible duplicate commitments from legitimate value stacking. Those rules should focus on whether a resource can satisfy each obligation, rather than treating participation in one program or market as a categorical bar to compensation for other distinct services.

iii. Compensation must be bankable

A market signal that changes frequently, is discretionary, or is available only after a full portfolio has materialized will not support investment. While DER are valuable in part because they can be deployed more quickly than utility-scale resources, developers still need reasonable certainty that a project in a particular location can produce a viable revenue stream. That certainty cannot depend on project-specific negotiations or market rules developed only after a

[2] Track 2 Workshop Report: TSO-DSO Coordination, at p. 6.
[3] *Ibid*, at p. 12.

resource seeks to participate. The Commission must therefore establish a durable, Commission-adopted compensation architecture in advance, rather than leave market rules and revenue opportunities to project-specific negotiations or utility discretion. That framework should provide prospective participants with clear, advance information regarding the applicable value categories, compensation methodology, expected duration of the need, and the terms under which payment will be available.

Clean Coalition recommends a framework that includes some combination of the following:

- multiyear availability contracts,
- capacity payments for committed local capability,
- performance payments,
- transparent locational adders,
- standardized market products, and
- forward procurement for forecast constraints.

The Piclo discussion supports this approach by showing that flexibility markets often begin with longer-term procurement for known system needs and later expand into day-ahead and intraday products. The Commission should require a similar progression here: establish durable, forward-looking compensation mechanisms first, then add shorter-term operational products as market capabilities mature. Without a sufficiently predictable and transparent revenue opportunity, the framework may identify local value in theory without creating the investment needed to deliver it in practice.

iv. Valuation should compare DER portfolios against infrastructure on an equivalent basis

The value of DER orchestration cannot be determined by evaluating each participating resource as a narrow customer program. The purpose of orchestration is to combine and coordinate distributed resources so that the resulting portfolio can perform functions traditionally supplied through utility infrastructure. A portfolio of local generation, storage, flexible load, managed charging, and other DER may collectively reduce peak demand, serve new load, relieve a local constraint, defer an upgrade, provide operational flexibility, and improve resilience. Where a DER portfolio also provides resilience, customer continuity, or Community Microgrid-enabling capabilities beyond the functions necessary to address the identified grid need, those distinct benefits should be separately recognized rather than excluded from the comparison.

Evaluating each component through a separate program or isolated value stream will systematically understate the value of the coordinated portfolio.

The workshop record supports treating orchestrated DER as planning-grade resources. PG&E described DER orchestration as enabling reliable, dispatchable, and measurable grid services and identified "resource-efficient grid investments" as a primary use case in which flexibility can reduce or defer distribution and transmission upgrades.[4] SCE similarly identified asset deferral, speed-to-power, operational flexibility, and improved utilization of existing infrastructure as principal sources of value.[5] These functions are not ancillary to the DSO framework; they are among the principal reasons to develop one.

The Commission should therefore require DER portfolios to be compared against traditional infrastructure whenever they can address the same identified grid need. That comparison should use equivalent assumptions concerning the location and timing of the need, planning horizon, service life, reliability, availability, performance, and risk. It should also account for the full costs and benefits of each alternative. Equivalent evaluation does not require DER portfolios to replicate every characteristic of a conventional asset; it requires both alternatives to be assessed against the functions necessary to resolve the identified grid need. *The infrastructure alternative should include capital expenditures, financing and rate-of-return costs, operations and maintenance, project-development timelines, permitting risk, and the potential for an asset to become underutilized as load forecasts change.*[6] The DER alternative should include procurement, compensation, telemetry, communications, DERMS integration, measurement and verification, administration, and any necessary contingency resources.

Equivalent treatment also requires symmetry in the treatment of forecasts and uncertainty. Utilities routinely plan and justify infrastructure investments based on forecast load growth and the probability that a constraint will arise in future years. DER portfolios should therefore not be assigned no value merely because the need has not yet fully materialized or because individual resources cannot independently replace the entire project. The relevant question is whether a reasonably procurable and orchestrated portfolio can satisfy the identified need with sufficient reliability, availability, and locational precision. Clean Coalition has

[4] Track 2 Workshop Report: Distribution System Operator DER Orchestration, at p. 3.
[5] *Ibid*, at p. 4.
[6] Clean Coalition Energy Tetris article on incorporating DER into energy planning. https://clean-coalition.org/news/energy-tetris-part-2-a-practical-blueprint-for-integrated-grid-planning-in-california/

previously recommended that DER portfolios compete against traditional infrastructure on precisely that basis.

DERMS is important to this comparison because it can convert a collection of individual customer resources into a coordinated grid resource. Forecasting, operating envelopes, dispatch signals, telemetry, aggregation, and performance verification can allow a portfolio to provide a defined and enforceable level of service. The framework should therefore evaluate the capabilities of the orchestrated portfolio, including the capabilities supplied through DERMS and aggregation, rather than limiting the analysis to the historical performance of individual demand-response programs. Modern portfolios may include dispatchable batteries, managed EV charging, flexible interconnection, demand response, virtual power plants ("VPPs"), and other resources that were not available or fully coordinated in earlier deferral solicitations. Expanding the range of eligible technologies and configurations can improve portfolio diversity, dispatchability, and overall reliability by allowing complementary resources to perform different functions and respond across different operating conditions. A clear, Commission-adopted framework established before IOU applications are filed would also guide developers, aggregators, and technology providers toward the capabilities and combinations most likely to create measurable ratepayer value.

This comparison should occur early enough to affect planning and procurement decisions. ***Once an infrastructure project is treated as the default solution and advanced through engineering, budgeting, and approval, a DER portfolio is placed at a structural disadvantage even when it could have met the need at lower total cost.*** The Commission should require the IOUs to identify candidate needs, develop an infrastructure-cost baseline, define the functional requirements that an alternative portfolio must satisfy, and provide an open opportunity for qualified DER providers to compete before the utility solution becomes effectively irreversible. *Before advancing an infrastructure project that could reasonably be addressed, in whole or in part, by an orchestrated DER portfolio, the IOU should be required to demonstrate that the relevant grid need was published with sufficient lead time, the functional requirements and comparison baseline were transparent, and qualified DER portfolios received a meaningful opportunity to compete.*

This approach is the practical application of Clean Coalition's Energy Tetris philosophy.[7] New load, DER deployment, distribution constraints, and infrastructure investments should not be planned in separate silos. Once the location and timing of a grid need are identified, the DSO should use DERMS and competitive procurement to determine whether the need can be shaped, shifted, or locally served before ratepayers are committed to additional infrastructure. Clean Coalition's EIS Part 2 comments explained that DER portfolios should be treated as capital resources capable of supplying stacked grid services, rather than as peripheral customer programs.[8]

The Commission should incorporate this requirement for equivalent-comparison into the statewide DER orchestration framework and require each IOU application to explain how DER portfolios will be screened, valued, procured, and compared against conventional investments. Without that requirement, DER orchestration may improve visibility and dispatch while leaving the existing wires-first planning paradigm largely unchanged.

Taken together, these principles would convert DER valuation from a collection of isolated program payments into a coherent market framework. Local and temporal valuation identifies where resources are needed, value stacking recognizes all compatible services they provide, bankable compensation enables those resources to be developed, and equivalent comparison allows orchestrated portfolios to compete fairly against conventional investments. The Commission should establish these principles before IOU applications are filed and require each application to demonstrate how they will be implemented.

E. The Commission should require the DER orchestration framework to value resilience and enable Community Microgrids (Questions 2, 5, 7, 16, 17, and 18)

Resilience should be treated as an integral function of DER orchestration, not as an ancillary customer benefit addressed only through separate microgrid or emergency-response programs. Coordinated DER portfolios can support local reliability during normal operations and provide additional capabilities during outages, including critical-load support, voltage and frequency regulation, grid-forming operation, black start, sectionalized service, and faster restoration.

[7] Clean Coalition Comments on Assigned Commissioner's Ruling Issuing Questions on the Electrification Impact Study Part 2 Final Reports, at p. 1, and 3-4.
[8] *Ibid*, at p. 6.

These capabilities are directly related to the DSO's responsibility to operate and optimize the distribution system safely and reliably.

The workshop record discusses several components of resilience but does not yet combine them into a clear framework for planning, procurement, valuation, and compensation. Clean Coalition has explained that the value of aggregating DER to achieve the scale needed for community resilience is tangible, particularly as California confronts extreme weather, disaster risk, and aging infrastructure. A complete DER orchestration framework should therefore identify which resilience capabilities can be measured and procured, how their performance will be verified, and how distinct resilience-related value will be recognized without duplicating compensation for other services.

Community Microgrids provide an important application of this principle***. A DSO should be able to identify substations, feeders, and load pockets where coordinated DER deployment can create immediate local reliability value while also establishing the foundation for future islanding.*** The framework should not require a complete Community Microgrid to exist before recognizing that value. Solar, storage, flexible load, communications, controls, grid-forming inverters, and black-start capability may be deployed incrementally, with each resource providing current grid services while contributing to a longer-term resilience configuration. Clean Coalition's workshop presentation explained that grid-forming and black-start capabilities are necessary for Community Microgrids, are meaningful project cost drivers, and may require explicit compensation if they are to be deployed before an outage occurs.[9]

This staged approach also avoids the artificial separation between "blue-sky" grid services and outage resilience. The same portfolio may reduce circuit loading, improve power quality, defer infrastructure, support resource adequacy, and serve customers during an interruption. Community Microgrids are therefore a particularly clear example of why DER should be evaluated as portfolios capable of providing stacked services rather than as isolated customer programs. Clean Coalition has previously explained that local solar, storage, managed charging, and Community Microgrids can simultaneously provide customer, distribution, resource adequacy ("RA"), and resilience value.

The Goleta Load Pocket illustrates the type of area the framework should be designed to address. It is a transmission-vulnerable and disaster-prone region where coordinated local DER

[9] Clean Coalition Presentation for Distribution System Operator Workshop, at slide 10.

could provide both ordinary grid services and protection against broader transmission outages. The DSO could initially coordinate DER at the feeder level to improve power quality, increase effective capacity, relieve local constraints, and defer infrastructure. Those same investments in resources, communications, controls, and operational coordination could then support staged development of a substation-level Community Microgrid, rather than requiring resilience capability to be designed and funded only after a major outage or after the complete microgrid is ready for construction.

The Commission should therefore require each IOU application to:

- identify transmission-vulnerable, disaster-prone, and critical-load areas where coordinated DER may provide material resilience value,
- explain how DERMS, communications, protection, switching, and operating procedures could support staged Community Microgrid development,
- define measurable resilience services and performance requirements,
- permit compensation for distinct grid-forming, black-start, islanding-readiness, restoration, and critical-load capabilities where they provide incremental value; and
- compare DER-based resilience portfolios with conventional reliability investments on an equivalent basis.

The Commission should not adopt a DER orchestration framework that optimizes the grid only while the upstream system is available. A modern DSO should use DER to improve everyday grid performance while deliberately building the local capabilities needed to maintain or restore service when the broader grid fails.

F. The Commission should require layered and interoperable DERMS that enable CCA and third-party participation (Questions 2, 5, 7, 10, 11, 13, 16, and 18)

DER orchestration should not require every participating resource to be enrolled in, controlled by, or directly integrated into a single IOU-operated DERMS platform. A scalable framework should instead use a layered architecture in which the DSO operates the grid-level systems needed to identify constraints, establish operating envelopes, communicate grid needs, and verify performance, while CCAs, aggregators, and other qualified providers may operate edge DERMS that manage portfolios and translate distribution-level requirements into customer- or device-level actions.

This structure preserves the IOU's ability to operate the distribution system safely without making the utility platform the exclusive gateway for market participation. The workshop report reflects Clean Coalition's recommendation that grid-level DERMS coordinate with CCA- and third-party-operated edge DERMS through open, interoperable interfaces.[10] CalCCA similarly cautioned that enterprise ADMS and DERMS platforms were developed primarily for utility operations and may not scale effectively to support large numbers of third-party resources.[11]

A layered structure also recognizes that different entities perform different functions. The DSO needs visibility into aggregate portfolio capability, expected availability, operating limits, dispatch status, and verified performance. It does not necessarily need direct control of every thermostat, battery, EV charger, or inverter. CCAs and aggregators can manage customer relationships, portfolio enrollment, forecasting, optimization, and device-level control while responding to standardized grid-service requests and operating constraints established by the DSO. This division of responsibilities can reduce integration complexity, preserve customer choice, and allow innovation at the grid edge. Experience in Great Britain demonstrates that local distribution needs can be coordinated through a layered structure in which distribution operators, independent aggregators, flexibility platforms, and the national system operator perform distinct but interoperable functions.[12]

i. CCAs need timely, actionable data to administer programs and participate in DER orchestration (Questions 2, 5, 7, 11(a), 12(a), 13, 16, and 18)

Layered DERMS cannot function without timely, standardized, and actionable data exchange. CCAs and third-party providers need sufficient access to customer-authorized usage data, DER characteristics, grid needs, operating constraints, program enrollment information, dispatch requirements, and performance data to forecast portfolio capability, design programs, site resources, avoid conflicting commitments, and respond to DSO needs. The relevant question is not whether CCAs should be given unrestricted access to utility operational systems, but whether the framework provides the data and interfaces necessary for them to participate on equal terms.

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[10] Track 2 Workshop Report: Distribution System Operator DER Orchestration, at p. 9.
[11] *Ibid*, at p. 8.
[12] See Ofgem, *Decision: Market Facilitator Delivery Body* (July 29, 2024) and *Decision: Market Facilitator Policy Framework* (June 4, 2025) (establishing an independent facilitator to coordinate and standardize local and national flexibility markets and reduce barriers to participation).

The Commission's Data Working Group record (in R. 22-11-013) demonstrates that existing CCA data access is fragmented, delayed, and inconsistent across utility territories. Clean Coalition has previously explained that when timely customer load data is unavailable or controlled through utility-specific systems, CCAs are constrained in their ability to forecast demand, design rates and programs, and support DER integration. The Data Working Group Report similarly identifies problems with the timeliness and accuracy of hourly and sub-hourly AMI data and notes that quarterly interconnection reports are too limited to support active DER procurement and program administration.

Those existing limitations will become more consequential as CCAs assume a larger role in operating DERMS platforms, aggregating VPPs, supporting Community Microgrids, and administering dynamic rates. These functions require more than delayed billing-quality data; they depend on sufficiently granular and timely information to forecast portfolio availability, communicate dispatch instructions, verify performance, reconcile settlements, and adjust operations as grid conditions change. The DER orchestration framework should therefore build upon the Data Working Group record by identifying the additional data elements, delivery intervals, and interfaces necessary for CCA-led portfolios to provide reliable grid services at scale.

At a minimum, the framework should establish statewide requirements for customer-authorized interval data, DER and program-enrollment information, portfolio-level operational data, standardized APIs, data-quality standards, and correction timelines. The required cadence should be matched to the function being performed: billing data may be delivered on a slower schedule, while forecasting, dispatch, settlement, and performance verification may require day-ahead, near-real-time, or similarly low-latency exchange.

The Commission has already established that CCAs are entitled to the relevant billing, usage, load, and customer information reasonably necessary to investigate, pursue, or implement meaningful CCA programs, and that utilities may not second-guess a CCA's determination that requested information is relevant.[13] The Commission should reaffirm that this principle extends to the data necessary for CCAs to administer dynamic rates, manage DERMS-enabled portfolios

[13] D.04-12-046 at Section V.D.3 and Conclusions of Law 30–32 ("Section 366.2(c)(9) requires the utilities to provide all relevant information required by CCAs to 'investigate, pursue or implement' meaningful programs" and "does not permit the utilities to deny CCAs access to relevant customer or load information"); see also D.05-12-041 at Section X.3 ("AB 117 does not permit the utilities to second guess a CCA's request for relevant information").

and VPPs, support Community Microgrids, and participate meaningfully in DER orchestration. That existing entitlement should be implemented through enforceable statewide requirements governing data content, accuracy, standardization, delivery intervals, interfaces, and correction timelines.

G. The Commission should use pilots to accelerate implementation and scaling, not defer foundational decisions (Questions 3, 4, 5, 7, 10, 15, 17, and 18)

Pilots can provide important information about the technical, operational, and commercial implementation of DER orchestration. They can test telemetry latency, dispatch performance, aggregator coordination, cybersecurity, customer participation, compensation levels, measurement and verification, settlement, and interoperability under real operating conditions. Pilots may also help identify new grid-service opportunities, refine the value stack, determine how existing DERMS capabilities should be expanded, and establish which procurement structures produce reliable services and measurable ratepayer savings.

Pilots should not, however, become a substitute for Commission decisions on the foundational architecture. Questions concerning open access, market governance, eligible participants, technology neutrality, the allocation of responsibilities between grid-level and edge DERMS, data access, valuation principles, and the treatment of compatible value streams are policy questions that should be resolved through a Commission-adopted framework. They do not require each IOU to conduct years of separate pilots before common rules can be established. ***Allowing the utilities to develop these principles independently through their own pilots would risk producing three incompatible architectures and making later statewide standardization more difficult.***

The IOU implementation proposals illustrate this concern. PG&E proposes an initial sandbox followed by piloting and later scaling. SCE proposes a phased process beginning with pilots and studies and progressing toward broader integration through 2033. SDG&E proposes a framework-first sequence followed by capability development, targeted pilots, readiness-driven applications, and eventual scaling, while opposing a uniform implementation deadline.[14] Although phased implementation is reasonable, a sequence in which each phase must be

[14] Track 2 Workshop Report: Distribution System Operator DER Orchestration, at p. 15.

completed before the next begins could postpone meaningful DER procurement for years while conventional infrastructure planning and investment continue on their existing schedules.

The Commission should instead adopt the foundational framework first and require pilots, IOU application development, and near-term procurement to proceed on coordinated and overlapping tracks. Pilots should test how the framework is implemented, not whether its core principles apply. Information produced through a pilot should be incorporated into pending applications and used to refine later implementation stages as it becomes available. The Commission need not wait for every pilot to conclude before authorizing functions that rely on mature technologies, established standards, or demonstrated market models.

This distinction is especially important because different questions require different forms of evidence. A pilot may be appropriate to determine the telemetry cadence needed for a particular service, evaluate aggregator performance, test a compensation level, or validate whether an orchestrated portfolio can reliably address a defined local constraint. A pilot is generally not necessary to determine that qualified third parties should receive nondiscriminatory market access, that statewide products should use common definitions, that legitimate value streams should remain stackable, or that IOU systems should interoperate with CCA- and third-party-operated platforms. Those foundational determinations should guide pilot design rather than remain open until the pilots are complete.

i. Pilots should be designed for decisions and scaling

Each pilot should begin with clearly defined questions, success metrics, reporting requirements, and a predetermined pathway to broader implementation. At a minimum, pilot proposals should identify:

- the grid need or framework question being tested,
- the existing record and prior pilots on which the proposal builds,
- the capabilities being evaluated,
- the number and types of resources and market participants included,
- the performance, cost, customer, and ratepayer-benefit metrics,
- the schedule for interim and final results,
- the criteria for modification, continuation, or scaling, and

- the regulatory mechanism through which successful results will be incorporated into applications, procurement, or planning.

A pilot should not be considered successful merely because the technology operated as designed. The relevant inquiry is whether the pilot demonstrates a practical pathway to procuring reliable DER services, reducing total costs, improving utilization of existing infrastructure, or accelerating energization. The workshop record identifies technical feasibility, commercial viability, operational integration, and workable participation pathways as appropriate functions for pilots. Those functions should be measured against explicit benchmarks established before the pilot begins.

The Commission should also require interim reporting rather than wait for a single final report. Useful findings may emerge before pilot completion and should be incorporated promptly into application requirements, market rules, DERMS development, and distribution planning. Interim reporting would also allow unsuccessful assumptions to be corrected without extending a pilot simply to complete its original schedule.

ii. Pilots should build on existing experience rather than restart the inquiry

The Commission should require each IOU to identify how a proposed pilot differs from and builds upon existing demand-response, managed-charging, flexible-interconnection, VPP, battery-control, DERMS, and local-flexibility activities. The record already contains substantial experience with customer enrollment, dispatch, aggregation, measurement, communications, and compensation. Existing programs may not answer every distribution-level orchestration question, but they should narrow the remaining questions and prevent duplication.

Where a capability is already sufficiently mature, the Commission should permit limited procurement or initial operational deployment while more complex functions continue to be tested. For example, a utility may be able to publish a defined local need and procure a standardized capacity or availability service before every element of real-time orchestration is complete. Similarly, third-party platforms and aggregators can participate through defined interfaces while deeper ADMS and DERMS integration continues. A staged rollout should therefore expand the range of operational services over time rather than delay all market activity until the complete end-state architecture is available.

iii. Different IOU readiness should affect implementation, not the statewide framework

The utilities' differing technical readiness may justify different implementation schedules for particular operational capabilities, but it should not delay adoption of common principles or allow each utility to define a different market. SDG&E's lack of a current DERMS may affect when it can perform certain location- and time-specific dispatch functions, while other pilots may be possible with existing infrastructure. The Commission should therefore distinguish between:

- framework readiness, which should be established statewide now,
- pilot readiness, which depends on the particular service and existing utility capabilities, and
- scaling readiness, which should be determined through objective performance and cost criteria.

This distinction would allow the Commission to establish a common destination while accommodating different technical starting points. It would also prevent the least-ready utility from setting the pace for statewide policy development.

The Commission should reject an implementation sequence in which foundational decisions are deferred until a series of open-ended IOU pilots is complete. It should adopt the common framework first, require pilots and application development to proceed promptly and in parallel, and establish deadlines and objective scaling criteria that convert successful demonstrations into procurement and operational deployment. Pilots should shorten the path to implementation, not become the path itself.

H. The Commission should convene a time-limited working group and promptly adopt a statewide regulatory framework

The Commission should convene a time-limited stakeholder working group to resolve the technical and implementation details needed to support a common statewide DER orchestration framework. The working group should not revisit whether foundational principles such as open access, technology neutrality, interoperability, legitimate value stacking, and equivalent comparison with infrastructure should apply. Those principles should be established by the Commission and used to define the working group's scope.

The working group should focus on producing concrete, decision-ready recommendations concerning:

- common grid-service products, definitions, eligibility rules, and performance obligations,
- locational and temporal valuation, compensation, and safeguards against genuine double counting,
- publication of grid needs and comparison of DER portfolios with conventional infrastructure,
- market governance, including independent or competitively neutral administration,
- the respective functions of grid-level, CCA, aggregator, and third-party edge DERMS,
- interoperability, telemetry, data access, cybersecurity, measurement and verification, and settlement,
- pilot design, interim reporting, and objective criteria for scaling,
- criteria for identifying infrastructure needs that must be screened for DER alternatives,
- a standardized IOU readiness rubric and application requirements, and
- participation pathways for CCAs, Tribal Nations, environmental and social justice communities, local governments, aggregators, and DER providers.

This scope would address the principal gaps remaining after the workshops. The reports identify the relevant policy areas and summarize competing perspectives, but they do not resolve market governance, establish a complete valuation methodology, define interoperable data and communications requirements, or provide a common standard for comparing IOU readiness. Without Commission direction on these subjects, separate IOU applications could produce materially different eligibility, compensation, technology, and data-access rules in each service territory. Clean Coalition has previously explained that such fragmentation would create unnecessary silos and make both market participation and Commission oversight more difficult.[15]

The working group should have a defined schedule, required deliverables, and active Energy Division management. A final report should identify areas of agreement, present specific alternatives where consensus is not achieved, and include proposed framework language rather than merely summarize stakeholder positions. The Commission should then permit comments on

[15] Clean Coalition Reply Comments on Assigned Commissioner's Ruling on Track 1 and Track 2 Distributed Energy Resources Orchestration, at p. 3 and 6.

that report and adopt the statewide framework through a decision before directing utility-specific applications. This general sequence is consistent with the pathway presented in the workshop record: working-group development, party comments, Commission framework adoption, and subsequent IOU implementation.

The process should move quickly. Clean Coalition recommends that the working group complete its report within approximately six months, followed by a prompt Commission decision establishing the framework, application requirements, performance metrics, and oversight standards.[16] IOU applications should then be filed on a common schedule or within Commission-established readiness tiers, with pilots and near-term implementation continuing in parallel. Differing technical readiness may justify phased utility implementation, but should not delay adoption of statewide rules or permit each IOU to design a separate market.

Each application should apply the adopted framework and include a standardized readiness showing, implementation milestones, near-term procurement opportunities, pilot integration plan, data-access plan, and explanation of how existing Commission-authorized DERMS, ADMS, communications, and grid-modernization investments will be used. The Commission should avoid duplicative cost recovery for capabilities already funded through general rate cases and limit application-specific recovery to incremental costs demonstrated to be necessary for DER orchestration. The workshop record likewise recognizes that existing funded technologies should be leveraged and that foundational technology costs ordinarily belong in general rate cases rather than being requested again through orchestration applications. Each application should also propose performance metrics and reporting that measure avoided infrastructure, energization speed, market participation, procurement outcomes, and actual ratepayer savings.

The Commission should use the working group to complete the framework, not postpone it. A time-limited process followed by a Commission decision and standardized IOU applications would preserve stakeholder input while preventing prolonged pilots, utility-specific architectures, and continued investment under the existing wires-first paradigm.

IV. CONCLUSION

[16] Alternatively, Clean Coalition supports UCAN's five-step regulatory pathway for developing demand-flexibility markets, to the extent it similarly results in a prompt Commission-adopted framework followed by standardized implementation.

Clean Coalition appreciates the opportunity to submit these comments. The workshop reports provide a strong foundation for DER orchestration, but they also show that the central architecture cannot be left to separate IOU applications or prolonged pilot processes.

The Commission should establish a common statewide framework that requires local-first optimization, open and competitively neutral markets, transparent and bankable compensation, interoperable participation by CCAs and third parties, and equivalent consideration of DER portfolios and conventional infrastructure. The framework should also recognize resilience and staged Community Microgrid development as integral functions of a modern DSO.

A time-limited working group should complete the remaining technical details, followed promptly by a Commission decision, standardized IOU applications, and parallel implementation. This pathway would convert the workshop record into near-term procurement and operational deployment while avoiding three incompatible markets and continued reliance on the existing wires-first planning paradigm.

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