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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 July 2, 2021)

ENVIRONMENTAL DEFENSE FUND COMMENTS ON ASSIGNED COMMISSIONER'S RULING ON TRACK 1 AND TRACK 2 DISTRIBUTED ENERGY RESOURCES ORCHESTRATION

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I. INTRODUCTION

The California Public Utilities Commission opened the High Distributed Energy Resources ("High DER") proceeding in 2021 to address topics related to electric load forecasting and system planning to support DER integration and electrification.[1] As part of the ongoing work in this proceeding, the Commission has focused on improvements to how the utilities integrate DERs, such as distributed generation and flexible loads, to improve system operations, decarbonization, and ratepayer affordability, including through DER orchestration. The California Future Grid Study Report, filed in September 2024, summarizes stakeholder input from three workshops hosted in early 2024 on opportunities and barriers to grid modernization to support additional DER integration.[2] On March 23, 2026, Commissioner Houck released the Assigned Commissioner's Ruling on Track 1 and Track 2 Distributed Energy Resources Orchestration ("DER Orchestration Ruling").[3] This ruling, drawing from the record in this proceeding and the California Future Grid Study Report in particular, identified five priority areas for further work as part of High DER Track 2's DER Orchestration Framework:

- DER Visibility to DSO;
- DER Visibility to CAISO;
- DER dispatchability/control;
- Open access to distribution system; and
- Reliability coordination at Transmission-Distribution (T&D) interface.[4]

The DER Orchestration Ruling included a number of questions on these topics (along with questions on the Integrated Capacity Analysis Workshops and the utilities' Grid Modernization reporting requirements) to inform two forthcoming workshops.[5] The Ruling set a deadline of April 13, 2026, for parties' opening comments, and April 20, 2026, for reply comments.[6] These

[1] R.21-06-017, *Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future* (June 24, 2021).
[2] R.21-06-017, *Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future*, Administrative Law Judge's Ruling Seeking Comments Regarding Future Grid Study Report (Oct. 17, 2024) [hereinafter "Future Grid Study Report"].
[3] R.21-06-017, *Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future*, Assigned Commissioner's Ruling on Track 1 and Track 2 Distributed Energy Resources Orchestration (Mar. 23, 2026) [hereinafter "DER Orchestration Ruling"].
[4] *Id.* at 3.
[5] *Id.*at 4-11.
[6] *Id.* at 14.

deadlines were subsequently extended to April 20, 2026, and April 30, 2026, respectively.[7] These Opening Comments are responsive to those rulings.

II. DISCUSSION

A. IOU DSO-led DER Orchestration Initiation

1) What should some of the primary objectives of IOU DSO-led DER orchestration be?

The Commission's three objectives for DER orchestration should be affordability, reliability, and sustainability. Any DER orchestration effort should be focused on implementing tools that support greater integration of zero-emission energy, support reliable grid operations and resiliency in the event of disruptions, and put downward pressure on rates when compared to the status quo. The Commission should judge the anticipated value of any DER orchestration framework based on its ability to achieve these three objectives, and will need to balance each of these goals in evaluating any frameworks. With respect to reliability in particular, DER orchestration can prevent grid constraints before they multiply. DER orchestration can be developed in a manner that supports reliability needs as a matter of first principles, but the operating and interconnection rules must be established consistently, and coupled with integrated planning and procurement frameworks that reward/penalize behavior that enhances/detracts from reliability based on the specific conditions of the grid.

The Commission should also ensure that efforts on this topic are complementary to, rather than duplicative of, its ongoing work on flexible service connections ("FSCs"). At least a portion of the Commission's work on FSCs, including that on dynamic FSCs in this proceeding, is directly relevant to the DER orchestration frameworks contemplated in the DER Orchestration Order. Both may require grid monitoring infrastructure such as an Advanced Distribution Management System ("ADMS") and/or a Distributed Energy Resource Management System ("DERMS"), and both can provide similar grid benefits in the form of mitigating or avoiding grid constraints. The high-confidence load flexibility offered by a customer under an FSC agreement is a form of DER orchestration, and customers agreeing to an indefinite FSC are providing value that warrants compensation. Rather than completing this work in separate siloes, the Commission should pursue these efforts in a coordinated manner, ensure the utilities are

[7] R.21-06-017, *Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future*, Email Ruling Granting Request for Extension on Comments and Workshop (Apr. 3, 2026).

designing DER orchestration frameworks and FSC programs that are complementary and cost-effective as a whole.

2) *What are the primary grid constraints that could be solved, or operational improvements that could be created, through implementation of a utility DSO-led DER orchestration?*

DER orchestration can help to mitigate, defer, or avoid grid upgrade needs, provide additional zero-emission energy and capacity, and provide ancillary services in a more effective, and cost-effective, manner when compared to non-orchestrated DERs, if well-implemented. Specific constraint resolutions and operational improvements include:

- Avoiding thermal overload at substation transformers and primary feeders
- Avoiding thermal overload at distribution secondaries and service transformer level
- Addressing reverse power flow implications (i.e., distributed generation ("DG") hosting capacity) during daytime minimum load conditions. Hosting capacity bottlenecks block new DER interconnection, and coordinated scheduling and dispatch of complementary DER operations can improve circuit-level hosting, for example, by charging energy storage resources during daytime minimum load conditions to allow more DG interconnection.
- Mitigating voltage violations under steady-state (static) power flow conditions. This is especially important for considering the impact of DERs that are uncoordinated from the grid. Typical IOU investments in assets such as voltage regulators and capacitor banks need to be sequenced and compared in a full economic assessment with inverter-based DERs that can provide similar levels of voltage regulation while also providing other grid services.
- Alleviating generator ramping constraints associated with the "duck curve" through coordinated DER behavior. This could begin with flattening the evening peak by shifting loads to daytime periods with high excess solar generation, but could also encompass more dynamic ramping constraints in real-time markets due to potential impacts from EV-fast charging.
- Supporting increased reserve requirements for increasing variable energy resource (VER) penetration on the CAISO system, and increasing variability of overall system net loads under high data center penetrations.

3) *What are appropriate valuation frameworks to quantify ratepayer value to potentially be unlocked through DER orchestration?*

DERs can provide many of the benefits of traditional resources operating in a wholesale market context, depending on the type of DER and how it is deployed. This includes energy, capacity, and ancillary services. In addition, DERs can provide location-specific benefits, such as addressing a distribution feeder-level constraint that would otherwise require a grid upgrade to address. Therefore, any valuation framework used to assess the ratepayer value needs to fully account for these potential benefits across the bulk power and distribution system.

The Commission should consider the feasibility and implications of developing a distribution locational marginal price ("dLMP"), or flexibility martket, framework to enable consistent evaluation of overall price impacts resulting from implementation of the IOU-DSO construct for DER orchestration. The appeal of implementing a dLMP construct is that it mirrors the price formation processes of the CAISO, but adds a distribution congestion and losses element into the equation. Pursuing this pricing structure from the outset would send strong price signals to developers about where to locate their investments. Regardless of the specific mechanism, the goal for the Commission should be to ensure that outcomes of any valuation framework applied to the DER orchestration fairly compare cost outcomes for energy and bulk power system services available today through CAISO, with the incremental future benefits of orchestrating DERs. Doing so will allow a realistic assessment of the impacts to affordability from investing in a DER orchestration effort.

Existing DER avoided cost analysis methodologies, the most recent being the Commission's 2024 Avoided Cost Calculator[8] are a useful starting point but should evolve toward more complex quantifications of ratepayer value. One such example of this leading-edge valuation methodology is that demonstrated by Pacific Northwest National Lab ("PNNL") evaluating the potential cost savings in ERCOT from implementing a DSO+T transactive energy model (which is similar to the DSO construct as part of the High DER proceeding).[9] EDF

[8] CPUC, 2024 Distributed Energy Resources Avoided Cost Calculator Documentation (Oct. 2, 2024), https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/demand-side-management/acc-models-latest-version/2024-acc-documentation-v1b_clean_posted_nowm.pdf.

[9] *See e.g.,* Reeve H.M., S.E. Widergren, R.G. Pratt, B. Bhattarai, S. Hanif, S.R. Bender, and T.D. Hardy, et al. 2022, https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-32170-1.pdf.

recommends that the IOUs work—potentially through collaboration with PNNL—to study the ISO-DSO potential cost savings from implementing DER orchestration that capture:

- Full distribution investment deferral savings based on realistic DER dispatch scenarios and potential;
- Impact on bulk system generator dispatch to capture full system cost savings from orchestrated DER operation;
- Impacts on long-term transmission expansion plans. DER orchestration must be valued with a primary goal of optimizing transmission buildouts, especially in the context of new large loads and data centers; and
- Full social welfare analysis to evaluate consumer surplus gains from implementing a DSO style DER orchestration model.

Lastly, for a compensation framework reflective of the value of orchestrated DERs, EDF recommends the Commission look to the valuation and compensation framework outlined in the *Distributed Energy Resource (DER) Integration Framework* published by Lawrence Berkeley National Laboratory ("LBNL") in 2025.[10] This framework proposes a grid services tariff aimed at compensating customers' load modification and/or export, paired with an export tariff to allocate and recover the costs of the electric grid attributable to serving these DERs.[11]

4) *Should the Commission adopt the following set of guiding principles to shape the proposed IOUs' DER orchestration framework applications?*
   - *Ratepayer benefit and protection*
   - *Technology-neutral, performance-based*
   - *Locational and temporal value recognition*
   - *Efficient operation of the grid*
   - *Open access and Interoperability*
   - *Transparent participation pathways and compensation*
   - *Incremental, evidence-based implementation*
   - *Equity and customer protection*
   - *Cyber-secure and resilient*
   - *Preventing double compensation*

   Should the Commission remove, modify, or clarify any of these guiding principles? Should the Commission add additional guiding principles? If the Commission adopts

[10] Matt McDonnel, Ron Nelson, and Natalie Mims Frick, *Distributed Energy Resource (DER) Integration Framework* (Jan. 2025), https://eta-publications.lbl.gov/sites/default/files/2025-02/der_integration_framework_final_20250117.pdf [hereinafter DER Integration Framework].
[11] *Id.*

these guiding principles, should there be an opportunity to refine them in any proceeding reviewing IOU applications?

EDF generally supports the above guiding principles, but provides the following recommendations:

- The "Technology-neutral, performance based" principle should be paired with "cost-reflective, bidirectional price signals" to maximize the economic efficiency of any framework. This topic is discussed in greater detail in response to Question 14 below.
- Regarding "Open access and Interoperability," open access distribution tariffs should be the goal, and more thought needs to be given to how procurement will evolve with this construct. More efficient market procurements and distribution-level auctions for larger resources may be best, but more investigation is needed.
- The "Incremental, evidence-based implementation" principle risks becoming a mechanism for delay if not paired with clear timelines and milestones. The topic of phased implementation plans is discussed further in response to Question 11 below.
- The Commission should clarify that the guiding principle of "efficient operation of the grid" means to increase the utilization of existing assets to reduce overall costs of building and maintaining the system.
- The "equity and customer protection" principle is underspecified. The Commission should specify the equity it intends the utilities to apply in designing their proposed frameworks (e.g. equitable access to the grid for customers deploying DERs, or equity in accessing the benefits of DER orchestration).
- The "preventing double compensation" principle should more clearly specify what harms it seeks to avoid.
- The Commission should add as a principle "data privacy and customer consent for behind-the-meter access." Any DER orchestration framework should include pathways to participate in the DSO-enabled grid services market that do not rely on top-down IOU control of every end use device. Other passive architectures, such as federated DERMS structures, can behave just as well in terms of providing grid services, while retaining customer control and privacy.[12]

[12] *See* EPRI, Federated Architecture for Distributed Energy Resources Integration (Dec. 2020), https://www.epri.com/research/products/000000003002019424.

Lastly, EDF supports refining these guiding principles as part of the review process for the IOUs' applications, as the principles may mean different things in practice as compared to in the abstract, and applying the principles to an actual application can help to improve both the principles and the application.

5) *How can findings from the Electrification Impact Study Part 2 (EIS Part 2) conducted as part of Track 1 of this proceeding inform the DER Orchestration application content? For example, can findings from EIS Part 2 inform the identification of areas best suited for piloting DER orchestration?*
    a. *Should the IOUs consider the results from the EIS Part 2 studies to phase implementation of DER Orchestration? If so, how should the results from the equity and enhanced demand flexibility scenarios in the EIS Part 2 studies be considered?*
    b. *Should the IOUs include examples based on the equity and enhanced demand flexibility scenarios in their proposed applications?*

The findings from the IOUs' EIS Part 2 Reports show that demand flexibility, such as that provided by orchestrated DERs, can be a valuable tool for reducing total system costs. It is not clear, however, from the IOUs' filed reports that these studies contain sufficiently granular data to directly inform the DER orchestration effort. The areas best suited for piloting DER orchestration in the near-term are those areas with meaningful levels and diversity of DER deployments today and a variety of grid constraint types and severities. If feasible, the utilities should leverage the underlying data used in development of the EIS Part 2 Reports in identifying those priority areas for implementing DER orchestration programs.

6) *Should the IOUs include a proposed shared savings mechanism (SSM) for successfully implementing DER Orchestration as part of the proposed application?*

EDF does not support the creation of a shared savings mechanism for DER orchestration itself. Successful interconnection and orchestration of DERs should be treated as part of the IOUs' obligation to serve, and therefore should not require an additional incentive mechanism for the utilities. The capital costs of projects needed to support DER interconnection and orchestration, namely distribution system grid modernization investments, such as ADMS and DERMS, as well as some complementary IT investments, are included in the IOUs' rate base and therefore earn a rate of return already. However, EDF recognizes that part of the move toward an IOU-led DER orchestration effort may require changes to the utility business model. EDF recommends the Commission instead consider implementation of an export tariff, as

detailed in LBNL's DER Integration Framework,[13] that would better align cost allocation and recovery of IOU capital investments and operating expenditures with the costs caused on the system by exporting DERs.

A well-designed performance incentive mechanism for the successful use of flexibility in place of system upgrades may be reasonable, but the Commission should consider this with caution. Given the stage of evolution in California with respect to IOU investment in DERMS and ADMS, care should be taken not to over-incentivize the development of DER orchestration if similar benefits can be achieved through a more market-based approach. For example, if least-cost grid expansion is a goal, then utilities would study the different needs and attempt to procure sufficient flexibility through service providers, potentially including the utility, of different products such as load shifting, load shedding, scheduling, etc. Under this scenario, IOUs would need to implement an appropriate distribution investment planning process that right-sizes traditional grid upgrades while maximizing the role of DERs in providing grid services. Potential new revenue streams associated with a DSO-style market implementation model, such as charging aggregators and flexibility service providers to connect to the grid and participate in the market, represent another avenue toward changing compensation that also fosters a future competitive distribution services market, versus relying on shared savings mechanisms.

In other words, the IOU-DSO construct should clearly be developed with rules governing the expectations of the IOU as a market maker. Because they are profiting from investments in the core underlying grid modernization investments, it may not be necessary to also establish a shared savings mechanism. In that case, the Commission may decide to simply implement rules that IOUs must optimize DER operation on the distribution grid as a condition of GRC investments in technology platforms.

7) *Should the IOUs include a review of the DSO incentive structures from regulators of other jurisdictions such as the United Kingdom (Ofgem) and Australia for discussion in stakeholder workshops?*

Yes. The United Kingdom has years of lessons from their incentive design structures to

[13] *Id.* at 26-39.

draw from.[14] Australia's virtual power plant trials also offer a useful, DER-specific data point.[15] Other jurisdictions may have similarly helpful learnings to draw from. This review, however, should contextualize these examples for California's IOU structure, as these countries' efforts may not be ready immediately copy and paste into California.

8) *Should the proposed applications address scaling and IOU readiness and the role of Advanced Distribution Management Systems/Distributed Energy Resources Management Systems (ADMS/DERMS)?*

Yes. The operability of ADMS/DERMS will likely be a critical component of meaningfully scaling DER orchestration, as real-time or near-real time visibility into grid conditions is needed to dispatch DERs without requiring very conservative safety margins. Multiple reports on the topic, including the U.S. Department of Energy's Virtual Power Plan Liftoff Report and an analysis from LBNL and The Brattle Group, identify the creation of scaling plans as critical to successfully growing these programs.[16] Currently, DERMS maturity and functionality varies significantly across the three IOUs. For example, PG&E has been piloting DERMs for several years and is in a second phase of scaling and refinement, whereas SDG&E has only recently submitted plans to procure a DERMS and is therefore much earlier in the process. The Commission should require the IOUs to detail the current capabilities of their ADMS/DERMS in the context of the DER orchestration frameworks they propose, how they expect those capabilities to change and improve over time, and how that change in capabilities will change the scope or characteristics of their DER orchestration. Ultimately, ADMS/DERMS

[14] *See, e.g.*, Ofgem, Energy Network Price Controls, https://www.ofgem.gov.uk/energy-regulation/how-we-regulate/energy-network-price-controls; Economic Consulting Associates, *An overview of Ofgem's latest electricity distribution price controls (RIOO-ED2)*, https://www.eca-uk.com/wp-content/uploads/2023/03/ECA-Overview-of-RIIO-ED2.pdf.

[15] *See, e.g.*, Western Power, Project Symphony Pilot, https://www.westernpower.com.au/resources-education/network-improvements/pilots--trials/project-symphony-pilot/; ARENA, *Project Symphony Platform Functional and Non-Functional Requirements Report* (Feb. 2022), https://arena.gov.au/knowledge-bank/project-symphony-platform-functional-and-non-functional-requirements-report/; ARENA, *Western Power – Project Symphony – Combined Platform (as built) Report for DSO, DMO, and Aggregator* (May 2023), https://arena.gov.au/knowledge-bank/western-power-project-symphony-combined-platform-as-built-report-for-dso-dmo-and-aggregator/.

[16] U.S. Department of Energy, Pathways to Commercial Liftoff: Virtual Power Plants, at 5 (Sep. 2023), https://climateprogramportal.org/wp-content/uploads/2025/06/LIFTOFF_DOE_VPP_2023.pdf; Ryan Hledik et al., *Distributed Energy, Utility Scale: 30 Proven Strategies to Increase VPP Enrollment*, at 58 (Dec. 2024), https://eta-publications.lbl.gov/sites/default/files/2024-12/30_strategies_to_increase_vpp_enrollment_12-19-2024.pdf.

capabilities shouldn't be an indefinite barrier; the Commission should set minimum viable thresholds for the utilities to hit to implement different elements of DER orchestration.

9) *How should the proposed applications demonstrate IOU readiness to implement DER orchestration? How should the Commission reconcile different states of readiness of each utility so that meaningful progress can be made?*

The Commission should require a standardized readiness rubric so comparisons are apples-to-apples across the IOUs. The IOUs should clearly define what level of investments in enabling technology are needed to achieve different levels of expected grid benefits, depending on where a particular IOU is on the continuum of IOU-led DER orchestration implementation. This includes requiring that the IOUs articulate different options for how levels of grid services can be obtained with differing levels of technology investment and end-to-end visibility and control. Doing this will require clearly defining potential value streams that do not rely on advanced coordination as a base comparison, and then incrementally identify added value layers that are clearly tied to additional technology investments. This would recognize that full DSO-led DER orchestration has a maturity curve where DER value and cost savings can be recognized at all stages, albeit to different degrees. Critically, the Commission should not let pace of implementation for all IOUs by set by the capabilities of whichever is least ready.

10) *Should the IOUs present their proposed strategy for achieving interoperability, including communications protocols, to enable scalable DER orchestration?*

Yes. Consistent with the "Technology-neutral, performance-based" and "open access and interoperability" principles listed in Question 4 above, interoperability is a key component of scaling DER orchestration. Any communications protocols used must allow for widespread participation by a diverse array of DERs from a wide range of technology providers. The utilities should avoid orchestration proposals that require customers to use a particular company's technology, either the DER itself or associated communications equipment, and instead should allow for allow for participation by customers who can meet existing communications protocols and other related standards. IEEE 2030.5 and OpenADR should be core components of the IOUs' protocols, and customers and aggregators should have clear guidance up-front on what additional protocols are required before investing in DERs.

11) Should the proposed DER Orchestration applications include a proposed phased implementation and deployment plan? If so, what elements should the plan contain?

Yes. The end-goal of the IOUs' DER orchestration frameworks should be universal availability across their service territories. Phased implementation/deployment may be preferrable, however, as the IOUs' capabilities increase over time, and to allow the utilities to identify and address unexpected issues at a smaller scale. Full integration with CAISO will also take time, given CAISO's slower pace of evolution. Phasing could take several forms, including targeting specific geographies, targeting specific customer classes/sizes, or with participation caps. But, upfront investment in sophisticated grid planning and optimization tools will help guide this evolution and will increase the efficacy of the earlier designs in terms of informing CAISO about DER aggregation and visibility needs, operational capabilities, etc. Some suggested levels to phasing include:

- Core technical capabilities demonstration (locational DER dispatch, remote disconnect power flows, demonstrated energy scheduling, voltage mitigation and VAR support);
- Integrate advanced distribution-level coordinated dispatch and planning, i.e., sending appropriate price signals to relieve distribution constraints such as reduced hosting capacity, thermal overloads on individual circuits, etc.; and
- Integration with CAISO
    - Start with simple use cases enrolling DERs into CAISO existing aggregate DER products and following existing market implementation guidelines.
    - Move toward two-level integrated resource optimization. This is where CAISO sets a first round of LMPs through portfolio optimization, and then integrates DSO results to add a second-order market clearing step.

The utilities should detail their proposed phasing plans as part of their applications. Such limitations should be paired with clear criteria for when participation will be scaled to include the next tranche of customers and ultimately all interested customers. This is especially important because PG&E is further along than both SCE and SDG&E, and so learnings from their initial efforts can inform procurements and buildouts of the other IOUs. EDF also recommends that any phasing not limit participation to any specific technology type (e.g. starting with only rooftop solar PV) as open access and interoperability is a key principle to this effort and incorporating additional technology types early can allow the IOUs to identify and address

issues and support further scaling. Lastly, the IOU's applications should detail the known barriers to each phase in their proposal and what steps the IOU is currently taking to address that barrier, or will need to take in the future.

12) What potential cost-effective mechanisms or measures could be included as part of the proposed DER orchestration framework to demonstrate a net benefit to ratepayers?

This effort should include transparent benefit-cost quantification and reporting at each implementation phase, as discussed further in response to Question 9 above. The Commission should require independent third-party verification of claimed savings from DER orchestration. In evaluating the overall benefit to ratepayers from DER orchestration, EDF recommends the utilities conduct the DSO+T modeling referenced in Question 3 above to quantify consumer welfare gains.

With respect to ADMS/DERMS in particular, these investments may represent a significant portion of the utility-side costs required for scaled deployment, but provide benefits beyond the DER orchestration context. For example, the utilities have cited their ADMS/DERMs investments as supporting the implementation of dynamic flexible service connection programs.[17] Given this, any benefit-cost analysis must consider what portion of the capital and operational costs of these systems is attributable to DER orchestration to avoid over- or under-estimating the costs of a DER orchestration framework as part of any cost-effectiveness tests and inadvertently socializing orchestration costs onto non-participating customers.

13) What potential benefit-cost methodology could these applications use?

As discussed in response to Question 3 above, the Commission's existing approved benefit-cost methodologies, namely the Total Resource Cost Test and the Societal Cost Test, are an appropriate starting point for benefit-cost analysis, but this should evolve to include more complex quantifications of ratepayer value. It is important that the Commission include use of the Societal Cost Test from the beginning, as improved DER orchestration can provide

[17] *See, e.g.*, R.21-06-017, *Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future*, Pacific Gas and Electric Company's (U 39 E) Response to Assigned Commissioner's Ruling Seeking Additional Information on DER Enabled Near Term Flexible Connections, at 5 (Nov. 25, 2025) ("PG&E then went beyond that offering to now provide the Flex Connect Program for customers who desire more flexibility than the Load Limit Letters offer, but it requires a communication system and DERMS.").

meaningful non-monetary benefits through avoided local air pollution and greenhouse gas emissions not accounted for in the Total Resource Cost Test, and the Commission has already stated that the Societal Cost Test "must be considered in all DER proceedings."[18]

Ultimately, circuit-specific distribution avoided cost values should be clearly identified as a goal for the IOUs to incorporate in successive implementation phases, including the development of a marginal cost of capacity to inform annual distribution system planning and investments.[19] The IOUs should also capture non-energy benefits (e.g. resilience, customer value of avoided outages) as qualitative indicators. These should be informed by the IOUs' required Risk-Based Decision-Making Framework and the Risk Assessment Mitigation Plans. Finally, the complete methodology to be used, and how that will to evolve over time, should be settled before the IOUs' applications are filed, not after, to ensure applications are based around clear and consistent benefit-cost quantification from the start.

14) How can IOU DSO-led DER Orchestration implementation be complementary and compatible with the potential rollout of real-time pricing?

Price signals and dispatch signals need to be coordinated, not competing. Real-time pricing can support DER Orchestration by allowing for DER dispatch/control based on economic signals reflecting real-time grid conditions, maximizing the benefits of the orchestration for participants and all ratepayers. The Commission recently declined to endorse symmetrical pricing, i.e. the same price for import as the compensation for export, as part of the demand flexibility proceeding, stating that it "would lead to cost-shifts to non-participating customers."[20] The rate design proposal outlined in the LBNL DER integration framework, discussed above in

[18] *See* R.22-11-013, *Order Instituting Rulemaking to Consider Distributed Energy Resource Program Cost-Effectiveness Issues, Data Access and Use, and Equipment Performance Standards*, Decision Adopting Societal Cost Test, at 2 (July 15, 2024).
[19] P. Andrianesis, M. C. Caramanis, R. D. Masiello, R. D. Tabors, & S. Bahramirad, "Locational Marginal Value of Distributed Energy Resources as Non-Wires Alternatives," 11 *IEEE Transactions on Smart Grid* 270 (2020), https://ieeexplore.ieee.org/document/8731686.
[20] R.22-07-005, *Order Instituting Rulemaking to Advance Demand Flexibility Through Electric Rates*, Decision Adopting Guidelines for Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company on Demand Flexibility Rate Design Proposals, at 95 (Aug. 29, 2025).

response to Question 3,[21] may be a useful mechanism to provide an efficient market signal while avoiding these cost shifts, as the export tariff applied to exporting DER customers would be designed to recover the system costs attributable to customers' export and could include the non-marginal costs included in rates currently, such as wildfire mitigation costs.[22]

15) How should the proposed DER Orchestration applications address the role and participation of DER aggregators within the proposed framework on issues such as coordination with the DSO, performance standards, data exchange requirements, and metrics to address accountability mechanisms?

Aggregators will be an essential part of scaling DER orchestration, as the IOUs likely cannot cost-effectively build direct relationships with millions of customers with millions of devices. Performance standards must apply uniformly to IOU-direct and aggregator-involved pathways to allow for a level playing field. Similarly, data exchange requirements will need standardization to avoid creating integration barriers unique to aggregators. In sum, the Commission should ensure that the utilities' applications adequately consider the role that aggregators will play in this space, and create accessible pathways to that participation.

16) Should the proposed DER Orchestration applications identify additional technology investments required to support DER orchestration implementation (e.g., DERMS enhancements, communications infrastructure, device-level controls)?

Yes. Identifying the technologies required to implement DER orchestration and to scale that orchestration, as well as the estimated incremental cost of those investments, is necessary to determine the cost-effectiveness of any orchestration framework. As discussed in response to question 12 above, some of these technologies such as DERMS provide benefits outside of the DER orchestration context, and their costs should be accounted for accordingly. As part of this identification of additional technology needs, the utilities should detail not just the technology's use in the context of DER orchestration but also other anticipated and potential uses of the technology and anticipated benefits.

In addition, customer-side device APIs and telemetry standard will also require attention to ensure that customers can participate in a cost-effective way while providing reliable response

[21] *See supra* note 10 at 29-39.
[22] R.22-07-005, *Order Instituting Rulemaking to Advance Demand Flexibility Through Electric Rates*, Decision Adopting Guidelines for Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company on Demand Flexibility Rate Design Proposals, at 96 (Aug. 29, 2025).

to IOU signals. As discussed in response to Question 10 above, interoperability should be a key priority, and customer-side technological requirements should reflect that.

17) Should the proposed DER Orchestration applications request details on whether the above mentioned technological capabilities should be customer-owned or utility-owned and what the estimated costs are?

Yes. This should include detailing not only what technologies should be customer- or IOU-owned, but also which technologies could be owned by either group and the benefits and drawbacks of the different ownership models. The preference should be for customer ownership of behind-the-meter devices, with IOU-defined standard for that device to interface with the grid.

The utilities should also describe potential tiers for participation and associated technological requirements and expected costs. For example, customer-deployed telemetry and communications equipment can increase the value of their DERs by allowing them to respond in real time to changing grid conditions and participate in ancillary services markets, but the up-front cost of these technologies can make such deployments cost-prohibitive for small customers. Customers and the IOUs will need to balance these costs with the added value of the solutions to determine the right mixture of technologies. These cost estimates (for both IOU and customer technology needs) should also be independently reviewed. Ultimately the choice should be up to the customer whether to install a certain technology and unlock its potential additional value, but initial analysis by the utilities at this stage would help in scoping the deployment of a DER orchestration framework.

B. Enabling DER Visibility to the CAISO and Coordination Between DSOs and CAISO

1) What issues should be addressed in the TSO-DSO workshop related to DER visibility and coordination under a DER orchestration framework?

The workshop should address the minimum viable data set CAISO actually needs for DER visibility and coordination, and what the IOUs can feasibly provide. According to the Future Grid Study gap assessment, "Increasing level of coordination [are] required when DERs [are] providing services to bulk power and distribution systems. Multiple questions remain unresolved in this area."[23] Therefore, IOUs should work with the CEC to study how DERs can

[23] Future Grid Study Report at 64.

provide grid services to the transmission system, and make presentations to a working group under this proceeding in terms of next steps to recommend a preferred approach to CAISO and ask for approval.[24]

2) Should operational requirements and wholesale market participation be considered?

Yes, DSO orchestration should not be designed in isolation from CAISO market structures. CAISO requirements may govern the behavior and scheduling of DER resources in the DSO DER orchestration portfolio, and therefore must be considered from both a valuation perspective (in terms of potential curtailment) and operational perspective. Behind-the-meter DER participation in wholesale markets can also create dual-signal conflicts that need explicit rules.

C. Cadence of Integrated Capacity Analysis Workshops

1) Should the ICA quarterly workshop requirement be reduced to biannual, aligning with the release of the biannual ICA reports?

2) Should the IOUs be authorized to submit a joint Tier 2 advice letter to propose modifications to the frequency of the ICA workshops?

D. Grid Modernization Reports

1) Should the Commission require the IOUs to submit their Biennial Grid Modernization Progress Reports in the fall of even-numbered years (e.g., 2026, 2028) to align with reporting requirements under Pub. Util. Code Section 913.6?

EDF supports aligning the utilities' Biennial Grid Modernization Progress Reporting requirement with the Commission's requirement to report to the legislature under P.U. Code Section 913.6. This statutory provision requires the Commission to report to the legislature "on the progress made toward modernizing the state's distribution and transmission grid and the impacts of distributed energy resources on the state's distribution and transmission grid and ratepayers." Shifting the timing of the utilities' reporting requirement to the fall of even-numbered years would allow the Commission's reporting to include more up-to-date information in its report while still allowing time to develop that report.

[24] The CEC has funded development of advanced distribution modeling tools, such as HiPAS (a more commercial version of GridLAB-D developed by PNNL), that allows high fidelity modeling of DERs both BTM and FTM, and can overlay different pricing structures and market models to evaluate DER response to ISO requirements. Understanding the dynamics and tradeoffs in a planning sense before launching into full development would be in the best interest of ratepayers, and provide stakeholders with valuable information.

2) *Should the Commission adopt the proposed Appendix A as the standardized format and content requirements for IOU's biennial grid modernization update?*

EDF generally supports the format and content requirements proposed in Appendix A. Suggested modifications to the proposal are included in response to Question 3 below.

3) *What additional information, if any, should be included in the reporting requirements?*

For each of the four subsections proposed in Appendix A (II.a through II.d), the proposal includes "benefits realized and current use cases" as well as "planned future use cases and anticipated benefits."[25] EDF recommends this be changed to "current use cases, with a quantitative and qualitative description of benefits for each use case," and "planned future use cases and a quantitative and qualitative description of anticipated benefits for each planned use case." A challenge for the Commission in regulating the utilities deployment of system-level tools such as ADMS/DERMS and AMI is that these tools can have a myriad of current and potential benefits, making it difficult to quantify the cost-effectiveness of individual use cases and of the tool as a whole. By modifying the reporting categories to require the utilities to quantify current and anticipated benefits, and to attribute those benefits to specific use cases, the Commission can collect the information necessary to ensure the utilities' use of these tools is cost-effective and in ratepayers' interests.

4) *What information, if any, should be omitted from the reporting requirements?*

5) *Should the Commission establish a sunset or review date for Appendix A reporting requirements to ensure alignment with the evolving grid modernization technology and goals?*

6) *Should the Commission require the utilities to use a Tier 1 or Tier 2 advice letter or other process to propose modifications to their grid modernization reporting approach or content?*

EDF supports requiring the utilities to submit a Tier 2 advice letter to propose modifications to their grid modernization reporting. Given the proposal to use Appendix A to standardize format and content for these filings, EDF recommends that the utilities be limited to

[25] P.U. Code §913.6.

modification requests that would apply uniformly across the utilities, and recommends that the Commission require the utilities to file such an advice letter jointly.

7) *Should the Commission authorize the Energy Division to direct changes to the content and format of the reporting approach?*

Yes. Such authority would be consistent with EDF's above recommendation allowing for modifications to the reporting requirements through a Tier 2 advice letter, which allows for Staff approval of the request. If Staff identifies a change that would improve the usefulness of the utilities' biennial reports, it should not need to wait for the utilities to submit an advice letter to make that change.

III. CONCLUSION

EDF thanks the Commission and utilities for the opportunity to provide these comments.

Respectfully submitted,

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