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TO PARTIES OF RECORD IN RULEMAKING 21-06-017:

This is the proposed decision of Commissioner Darcie L. Houck. Until and unless the Commission hears the item and votes to approve it, the proposed decision has no legal effect. This item may be heard, at the earliest, at the Commission's October 29, 2026, Business Meeting. To confirm when the item will be heard, please see the Business Meeting agenda, which is posted on the Commission's website 10 days before each Business Meeting.

Parties of record may file comments on the proposed decision as provided in Rule 14.3 of the Commission's Rules of Practice and Procedure.

/s/ MICHELLE COOKE
Michelle Cooke
Chief Administrative Law Judge

MLC:cg7
Attachment

Decision **PROPOSED DECISION OF COMMISSIONER DARCIE L. HOUCK**
(Mailed 09/25/2026)

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

DECISION ADOPTING AN APPLICATION PROCESS FOR UTILITY DISTRIBUTED ENERGY RESOURCES ORCHESTRATION AND ORDERING UTILITIES TO INCORPORATE LOAD FLEXIBILITY SCENARIOS INTO THEIR DISTRIBUTION PLANNING AND EXECUTION PROCESSES

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DECISION ADOPTING AN APPLICATION PROCESS FOR UTILITY DISTRIBUTED ENERGY RESOURCES ORCHESTRATION AND ORDERING UTILITIES TO INCORPORATE LOAD FLEXIBILITY SCENARIOS INTO THEIR DISTRIBUTION PLANNING AND EXECUTION PROCESSES

Summary

This decision orders Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company, collectively the Investor-Owned Utilities (IOUs), to retain a consultant to lead a series of working group meetings to vet proposals for a common Distributed Energy Resources (DER) orchestration framework, and prepare a report with recommendations based on the stakeholder feedback in the workshops. The report will be included as an attachment to the Joint IOU Application to be filed within 12 months of the issuance of this decision with the following goals:

- Developing a comprehensive, common proposal defining grid services and use cases for DER orchestration.
- Establishing open, interoperable communications for improved DER visibility and behind-the-meter grid services.
- Identifying distribution-level flexibility dispatch mechanisms.
- Enabling DER visibility to the California Independent System Operator and allowing for transmission system operator-distribution system operator coordination.
- Defining performance metrics, evaluating existing pilots and new use cases, and establishing scaling criteria.

This decision also directs the IOUs to organize a full-day stakeholder workshop presenting new Load Flexibility Scenarios that they will incorporate as a fourth modeling scenario in the annual Distribution Planning and Execution Process (DPEP) starting with the 2027-2028 cycle. This decision directs the IOUs within 75 calendar days of this decision to hold a workshop to present their

proposals for a Load Flexibility Scenario as a fourth scenario within the existing DPEP Scenario Planning Framework. The decision directs the IOUs to file a joint Tier 3 advice letter within 60 calendar days after the workshop providing the technical basis for Load Flexibility Scenario inputs and proposing implementation timing..

This proceeding remains open to address Track 3 issues.

1. Background

1.1. Factual Background

1.1.1. Track 2

The use of distributed energy resources (DERs)[1] – including demand-side management, electric vehicle (EV) infrastructure, and battery storage– is expected to increase due to California's transportation electrification policies and climate and reliability goals.[2] In addition, financial incentive programs for DER investment, legislation aimed at reducing greenhouse gas (GHG) emissions from

[1] "Distributed energy resources" means distributed renewable generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies" (Assembly Bill (AB) 327 (Perea, Chapter 611, Statutes of 2012) and Public Utilities Code Section 769(a)). The Federal Energy Regulatory Commission (FERC) defines distributed energy resources "as any resource located on the distribution system, any subsystem thereof or behind a customer meter. … These resources may include, but are not limited to, resources that are in front of and behind the customer meter, electric storage resources, intermittent generation, distributed generation, demand response, energy efficiency, thermal storage, and electric vehicles and their supply equipment" (FERC Order No. 2222, 86 Federal Register 16511, June 1, 2021 at 11).

[2] See Executive Order B-48-18, Executive Order N-79-20, and the California Energy Commission (CEC) 2018 Electric Vehicle projections in the Staff Report, California Plug-In Electric Vehicle Infrastructure Projections: 2017-2025 (Docket 17-ALT-01, 2018-2019 Investment Plan Update for the Alternative and Renewable Fuel and Vehicle Technology Program).

buildings, Commission proceedings,[3] and local reach codes[4] are likely to further drive electrification.

The expected high penetration of DERs in California's electric system creates challenges and opportunities for distribution system operations with the increase in two-way power flows and the expansion of distributed generation and storage options. These developments are likely to increase the potential for greater flexibility and efficiency in operating the distribution system, which may in turn improve day-to-day reliability for customers, enable faster and deeper decarbonization by reducing distribution system reliance on fossil fuel generation to ensure reliability, and mitigate costs required to ensure distribution systems are capable of maintaining reliable electric service during expected local peak load conditions. In order to address gaps in the current distribution system and maximize ratepayer value, the Commission identified the need for a DER orchestration framework in various proceedings, including this Rulemaking (R.) 21-06-017.

DER orchestration is the coordinated management of DERs by a distribution system operator (DSO), in this case a utility acting as a DSO.[5] Using

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[3] AB 3232 (Friedman, Chapter 373, Statutes of 2018), Senate Bill 1477 (Stern, Chapter 378, Statutes of 2018), Building Decarbonization proceeding (R.19-01-011), and Long-Term Gas System Planning proceeding (R.20-01-007).

[4] Reach codes are local building codes that seek higher energy savings and emission reductions than those required by the State's building energy efficiency standards (California Code of Regulations, Title 24, Part 6).

[5] In California, DSO functions, including distribution system planning and operations, are provided by the electric Investor-Owned Utilities (IOUs). As the market evolves into a high-penetration DER scenario, IOU roles may also evolve with a potentially growing need to consider different DSO roles. The term, "DSO" often refers to conceptual models designed to efficiently operate distribution systems with high numbers of DERs. The various DSO models present alternative approaches to distribution system planning and operations that may help

Footnote continued on next page.

visibility, forecasting, and control/scheduling tools, DSOs identify location- and time-specific distribution needs and signal eligible DERs (directly or via aggregators) to deliver verifiable services that align with those needs. This approach could support operational reliability and advance long-term decarbonization goals by integrating renewable energy sources and reducing fossil fuel reliance.

DER orchestration aims to create efficiency by increasing capacity utilization, avoiding capacity upgrades, and unlocking operational efficiencies. If successful, DER orchestration could contribute to ratepayer cost reductions, maintain system safety and reliability, and support long-term decarbonization goals.

1.2. Legislative Background

Assembly Bill (AB) 327 (Perea), Stats. 2013, ch. 611 instituted a number of changes impacting regulated utility service and the energy market, including those impacting net energy metering, natural gas and electricity rates, and DERs. AB 327 created Section 769 of the Public Utilities Code (Pub. Util. Code),[6] which requires the Commission to review, modify, and approve IOU distribution resources plan (DRP) proposals. DRPs assess the locational value and costs of distributed resources, propose mechanisms for deploying cost-effective solutions, outline ways to coordinate existing programs, identify utility spending needed for DER integration, and address barriers to DER deployment. IOUs were required to submit DRPs no later than July 1, 2015.[7]

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integrate DERs at least cost by increasing DER market opportunities and value capture while maintaining system safety and reliability.

[6] All subsequent statutory references are to the Public Utilities Code unless otherwise specified.

[7] Section 769(b).

1.3. Procedural Background

The Commission opened two proceedings in 2014, R.14-08-013[8] and R.14-10-003,[9] to fulfill the requirements of Sections 454.5(b)(9)(c), 701.1(a), 769, and 8360(c-i). Both proceedings were closed as of 2022.[10]

R.14-08-013 focused on distribution planning and developing tools to facilitate DER integration. R.14-10-003 focused on DER sourcing mechanisms.[11] Since 2014, R.14-08-013 and R.14-10-003 have accomplished the following items relevant here:

- Implemented a Request for Offers solicitation process to procure DERs that can defer grid investments.[12]
- Made significant progress on an alternate DER procurement process using tariffs.[13]
- Developed Integrated Capacity Analysis (ICA) and Locational Net-Benefit Analysis (LNBA) tools with

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[8] *Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769*, August 20, 2014.

[9] *Order Instituting Rulemaking to Create a Consistent Regulatory Framework for the Guidance, Planning, and Evaluation of Integrated Demand-Side Resource Programs*, October 8, 2014.

[10] Decision (D.) 21-09-005 and D.22-05-002.

[11] DER sourcing mechanisms refers to Section 769(b)(2), which requires utilities to "propose or identify standard tariffs, contracts, or other mechanisms for the deployment of cost-effective distributed resources that satisfy distribution planning objectives."

[12] D.16-12-036 adopted the Competitive Solicitation Framework for R.14-10-003 that was applied to the Distribution Investment Deferral Framework (DIDF) pursuant to D.18-02-004 for R.14-08-013.

[13] D.21-02-006 adopted the Partnership Pilot to test a new DER Deferral Tariff in the DIDF. It also adopted significant reforms to streamline DIDF Request for Offer solicitation processes, including the pilot of a new Standard Offer Contract mechanism.

sufficient data provided on the DRP Data Portals[14] to facilitate third party DER siting and planning.[15]

- Addressed confidentiality concerns such that the IOU distribution planning filings could be made public with minimal exceptions and DER siting tools could be hosted on public DRP Data Portals.
- Ensured IOU General Rate Case (GRC) filings address the technology and grid upgrades necessary to integrate DERs in accordance with a Grid Modernization Framework.[16]

The Commission opened R.21-06-017 on June 24, 2021 to study the impacts of high penetrations of DERs on the grid, identify better forecasting strategies, and plan and operate a distribution system that can support a large number of DERs on the grid. This rulemaking also addresses unresolved and ongoing issues from the predecessor proceedings including grid volatility from unstructured DER growth and impacts on Environmental and Social Justice (ESJ) communities.[17] Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) were named Respondents to this proceeding.

A prehearing conference was held on August 17, 2021, to discuss issues to be scoped into the proceeding and the schedule.

An Assigned Commissioner's Scoping Memo and Ruling (Initial Scoping Memo) issued on November 15, 2021 set forth the issues, need for a hearing,

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[14] The DRP Data Portals hosted by the three utilities provide ICA, LNBA, and other data to the public.

[15] D.17-09-026 adopted the ICA and LNBA tools for R.14-08-013.

[16] D.18-03-023 adopted requirements for IOU Grid Modernization Plans to be included in their GRC filings.

[17] *Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future*, Appendix C, June 24, 2021 for a full list of unresolved issues.

schedule, category, and other matters necessary to scope this proceeding pursuant to Code Section 1701.1 and Article 7 of the Commission's Rules of Practice and Procedure (Rules). The Initial Scoping Memo organized this proceeding into three tracks addressing distribution planning and execution, operational needs, and smart inverter operationalization and grid modernization. This decision addresses issues in Tracks 1 and 2, which considers distribution planning process and data improvements and IOU-led DSO roles and responsibilities in DER orchestration.

An Assigned Commissioner's Amended Scoping Memo and Ruling (Amended Scoping Memo) was issued on August 11, 2023 streamlining the process for resolving scoped issues and updating the procedural schedule. The Amended Scoping Memo laid out the following two issues for Track 2:

1. What are the operational needs necessary to efficiently operate a high DER grid and unlock economic opportunities for DERs to provide grid services, limit market power, reduce ratepayer costs, increase equity, support grid resiliency, and meet State policy objectives? and
2. What are the existing gaps and barriers in achieving the needs identified above within our current IOU-operated DSO? What are the potential solutions in overcoming these barriers?

The adopted schedule included a Future Grid Study workshop series hosted by the Commission's consultant, Gridworks. The workshops provided parties and other stakeholders an opportunity to collaborate on ideas for modernizing the electric grid for a High DER future. The workshop series culminated in a workshop report referred to as the Future Grid Study Report (FGS Report).[18]

An Administrative Law Judge (ALJ) Ruling issued on October 17, 2024 (October 17 Ruling) published the FGS Report and sought party comment on its findings. The FGS Report offered a comprehensive account of the three workshop topics: (1) distribution system operational needs to enable a "High DER Future"; (2) the gaps between current distribution system operational capabilities and identified operational needs; and (3) a set of recommendations to address the identified gaps.

The FGS Report identified remaining gaps and uncertainties including:

- Proposed future capabilities depending on the IOUs' progress in implementing their Grid Modernization Plans.
- Gaps in the operational interface between the California Independent System Operator (CAISO) and DSOs.
- The pace of developing grid services markets.
- Diverging visions of the High DER Future.
- Friction points over data sharing and transparency in DER interconnection.

On December 6, 2024, PG&E and SCE filing jointly; SDG&E; Natural Resources Defense Council (NRDC), Environmental Defense Fund (EDF), and CALSTART filing jointly; Center for Biological Diversity (CBD), 350 Bay Area, and The Climate Center filing jointly; CAISO; Green Power Institute (GPI); California Community Choice Association (CalCCA); Utility Consumers' Action Network (UCAN); Vote Solar; the Public Advocates Office at the California Public Utilities Commission (Cal Advocates); 350 Bay Area, CBD, Microgrid

[18] Future Grid Study Report issued September 30, 2024: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M543/K418/543418944.PDF

Resources Coalition, The Climate Center, GPI, and Clean Coalition filing jointly; OhmConnect; and the Vehicle-Grid Integration Council (VGIC) filed opening comments on the October 17 Ruling. On December 9, 2024 Advanced Energy United (AEU) filed opening comments to the October 17 Ruling. On January 6, 2025 Vote Solar filed reply comments, and on January 10, 2025, SDG&E, Small Business Utility Advocates (SBUA), Center for Energy Efficiency and Renewable Technologies (CEERT), PG&E and SCE filing jointly, NRDC and EDF filing jointly, AEU, VGIC, CalCCA, Clean Coalition, and GPI and Clean Coalition filing jointly filed reply comments on the October 17 Ruling.

An Assigned Commissioner's Ruling, issued on March 23, 2026, (March 23 Ruling) focused Track 2 on the development of a DER orchestration framework for IOU-DSOs. The ruling proposed a procedural approach beginning with two Commission-led workshops to build early alignment on key technical conceptual and market issues, followed by formal applications from the IOUs to develop and operationalize the full DER orchestration framework.

On April 17, 2026, Universal Devices filed opening comments in response to the March 23 Ruling. On April 20, 2026, Nexamp, Inc., Clean Coalition, Cal Advocates, PG&E, EnergyHub, SCE, 350 Bay Area, CALSSA, UCAN, CAISO, CalCCA, SBUA, EDF, SDG&E, AEU, and California Efficiency + Demand Management Council filed opening comments in response to the March 23 Ruling.

On April 29, 2026, Universal Devices filed reply comments to the March 23 Ruling. On April 30, 2026, EnergyHub, EDF, PG&E, Weave Grid, Inc. (Weave Grid), Clean Coalition, SCE, CBD and 350 Bay Area filing jointly, SDG&E, CalCCA, AEU, UCAN, SBUA, and Cal Advocates filed reply comments to the March 23 Ruling.

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

On June 5, 2026, Energy Division staff convened the second workshop focusing on TSO-DSO Coordination to discuss topics identified in the March 23 Ruling related to enhancing CAISO DER visibility, strengthening TSO-DSO coordination, and aligning responsible entities on shared priorities for DER integration and grid operations in a high-DER future.

An Assigned Commissioner's Ruling was issued on July 9, 2026 (July 9 Ruling) publishing reports summarizing discussion at both the May 21, 2026 and June 5, 2026 workshops and requesting comments on the workshop reports.

On July 27, 2026, PG&E, CalCCA, CAISO, SDG&E, EDF, CALSSA, Clean Coalition, SCE, CBD, Weave Grid, Universal Devices, California Energy Storage Alliance (CESA), AEU, UCAN, and Cal Advocates filed opening comments in response to the July 9 Ruling. On July 31, 2026, SBUA, SCE, CA Efficiency + Demand Management Council, EDF, Weave Grid, CBD, SDG&E, Clean Coalition, CalCCA, CALSSA, and PG&E filed reply comments in response to the July 9 Ruling.

1.4. Submission Date

The matter on Track 1 and 2 issues was submitted on July 31, 2026 upon receipt of reply comments in response to the July 9 Ruling.

2. Issues Before the Commission

The Track 2 issues before the Commission are as follows:

1. What are the operational needs necessary to efficiently operate a high DER grid, unlock economic opportunities for DERs to provide grid services, limit market power, reduce ratepayer costs, increase equity, support grid resiliency, and meet State policy objectives?
2. What are the existing gaps and barriers in achieving the needs identified above within our current Distribution System Operators? What are the potential solutions in overcoming these barriers?

The Track 1 issue addressed in this decision is are the following:

1. Track 1, Phase 2, Issue 1: How should Utilities better integrate DERs into their standard annual DPEP? How should the Utility DPEPs improve to provide transparency, capture additional value from DERs, and optimize DER siting?

This decision addresses the Track 1 and Track 2 issues listed above. This proceeding remains open to address Track 3 issues.

3. Primary Grid Constraints and Objectives of DER Orchestration

The March 23 Ruling asked parties to comment on what the primary objectives of IOU DSO-led DER orchestration should be, which primary grid constraints could be solved, and which operational improvements could be created through a utility DSO-led DER orchestration framework. The purpose of these questions is to create early alignment between parties on the goals of DER orchestration before IOUs prepare formal applications.

3.1. Primary Objectives

Numerous parties urged that ratepayer benefits and affordability should be primary objectives of DER orchestration.[19] PG&E and EDF state that DER orchestration should enable DERs to put downward pressure on electric utility rates.[20] CalCCA includes societal and equity benefits for ratepayers as primary objectives of DER orchestration alongside economic benefits.[21] Cal Advocates, AEU, PG&E, CAISO, and Universal Devices support operational cost reductions as a goal of DER orchestration.[22] For example, Cal Advocates explains that DER orchestration could reduce operational costs through increased utilization of existing distribution capacity and deferral of traditional infrastructure upgrades.[23]

PG&E, SCE, SDG&E, CAISO, Weave Grid, and EDF support reliability as a primary goal of IOU-led DER orchestration.[24] SCE includes safety through

[19] PG&E Opening Comments on March 23 Ruling at 1, SCE Opening Comments on March 23 Ruling at 2, Cal Advocates Opening Comments on March 23 Ruling at 6, 350 Bay Area Opening Comments on March 23 Ruling at 2, CALSSA Opening Comments on March 23 Ruling at 2, UCAN Opening Comments on March 23 Ruling at 2, EDF Opening Comments on March 23 Ruling at 3, AEU Opening Comments on March 23 Ruling at 12, Weave Grid Reply Comments on March 23 Ruling at 2.

[20] PG&E Opening Comments on March 23 Ruling at 1, EDF Opening Comments on March 23 Ruling at 3.

[21] CalCCA Opening Comments on March 23 Ruling at 13.

[22] Cal Advocates Opening Comments on March 23 Ruling at 6, AEU Opening Comments on March 23 Ruling at 12, PG&E Opening Comments on March 23 Ruling at 1, CAISO Opening Comments on March 23 Ruling at 11, Universal Devices Opening Comments on March 23 Ruling at 2.

[23] Cal Advocates Opening Comments on March 23 Ruling at 7.

[24] PG&E Opening Comments on March 23 Ruling at 1, SCE Opening Comments on March 23 Ruling at 2, SDG&E Opening Comments on March 23 Ruling at 4, CAISO Opening Comments on March 23 Ruling at 11, Weave Grid Reply Comments on March 23 Ruling at 2, EDF Opening Comments on March 23 Ruling at 3.

operational visibility as a goal.[25] PG&E, SCE, CalCCA, and Nexamp list accelerating customer energization, or "speed to power," as another primary goal.[26]

SDG&E, CalCCA, and 350 Bay Area state that DER orchestration should create customer and aggregator participation pathways.[27] 350 Bay Area and Nexamp note that transparent, bankable compensation for distribution-level services should be a method for increasing participation.[28] AEU highlights open access to the grid to facilitate solutions to low-cost grid services.[29]

SDG&E, Universal Devices, and Nexamp support DER visibility and coordination for the DSO as a primary objective.[30] EDF and 350 Bay Area list climate goals such as sustainability and emissions reduction as primary goals.[31] The California Efficiency + Demand Management Council emphasizes that the Commission should aim to coordinate related proceedings, including those regarding demand response, DER cost effectiveness, data access, and equipment performance standards.[32]

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[25] SCE Opening Comments on March 23 Ruling at 2.

[26] PG&E Opening Comments on March 23 Ruling at 1, SCE Opening Comments on March 23 Ruling at 2, CalCCA Opening Comments on March 23 Ruling at 13, Nexamp Opening Comments on March 23 Ruling at 3.

[27] SDG&E Opening Comments on March 23 Ruling at 4, CalCCA Opening Comments on March 23 Ruling at 13, 350 Bay Area Opening Comments on March 23 Ruling at 2.

[28] 350 Bay Area Opening Comments on March 23 Ruling at 2, Nexamp Opening Comments on March 23 Ruling at 3.

[29] AEU Opening Comments on March 23 Ruling at 12.

[30] SDG&E Opening Comments on March 23 Ruling at 4, Universal Devices Opening Comments on March 23 Ruling at 2, Nexamp Opening Comments on March 23 Ruling at 3.

[31] EDF Opening Comments on March 23 Ruling at 3, 350 Bay Area Opening Comments on March 23 Ruling at 2.

[32] California Efficiency + Demand Management Council Opening Comments on March 23 Ruling at 4.

The Commission agrees with parties that net ratepayer benefits, operational cost reductions, reliability, customer and aggregator participation, and emissions reduction should be some of the objectives of DER orchestration. Speed-to-power issues are being addressed in Track 3 on Flexible Connections and in the Energization proceeding R.24-01-018. Aggregator pathway objectives of DER Orchestration are intended to promote a means to support the objectives discussed further in Section 6.2 below. As stated in the OIR of this proceeding, "a great deal of work remains to ensure the grid can efficiently and cost effectively support the growth of DERs."[33] The identified objectives will advance efficiency and cost-effectiveness in integrating DERs into the overall electricity grid and will necessarily involve quicker energization and speed-to-power processes, as identified by PG&E, SCE, CalCCA, and Nexamp, as well as a more reliable grid, as highlighted by PG&E, SCE, SDG&E, CAISO, Weave Grid, and EDF. The Commission agrees with Cal Advocates' position that DER orchestration should be pursued to the extent that it reduces ratepayer costs and its benefits can be measured and evaluated through successful interventions.[34]

3.2. Primary Grid Constraints and Operational Improvements

The March 23 Ruling asked parties which primary grid constraints could be solved, and which operational improvements could be created through implementation of a utility DSO-led DER orchestration framework.

[33] *Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future*, June 24, 2021 at 13.

[34] Cal Advocates Opening Comments on March 23 Ruling at 4.

Multiple parties list overload mitigation as a primary grid constraint that could be addressed through DER orchestration.[35] The IOUs list several distribution constraints that could be solved through DER orchestration, including thermal overloads, customer energization and interconnection delays, system peak loading, and voltage deviations.[36] SCE and SDG&E state that DER orchestration could help defer distribution investments.[37] Cal Advocates emphasizes that while DER orchestration could help address local distribution capacity constraints, the Commission should require proof of cost-effectiveness per use case.[38] CAISO states that DER orchestration combined with CAISO coordination could support enhanced demand forecasting and resilient, forward-looking operations.[39] Universal Devices highlights that constraints such as voltage deviations caused by high residential solar export can only be resolved if behind-the-meter (BTM) orchestration is within the framework scope.[40] CALSSA argues that grid construction will still need to be done despite the potential of DER orchestration to support thermal overload mitigation and reduce peak load growth.[41]

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[35] PG&E Opening Comments on March 23 Ruling at 2, SCE Opening Comments on March 23 Ruling at 3, SDG&E Opening Comments on March 23 Ruling at 5, CALSSA Opening Comments on March 23 Ruling at 3.

[36] PG&E Opening Comments on March 23 Ruling at 2, SCE Opening Comments on March 23 Ruling at 3, SDG&E Opening Comments on March 23 Ruling at 5-7.

[37] SCE Opening Comments on March 23 Ruling at 3, SDG&E Opening Comments on March 23 Ruling at 5-6.

[38] Cal Advocates Opening Comments on March 23 Ruling at 7-8.

[39] CAISO Opening Comments on March 23 Ruling at 12.

[40] Universal Devices Opening Comments on March 23 Ruling at 2-3.

[41] CALSSA Opening Comments on March 23 Ruling at 3.

AEU notes that individual IOU DER orchestration frameworks without consistent infrastructure, systems, processes, and protocols threaten to limit operational improvements and grid constraints that may be addressed.[42]

The Commission agrees with the IOUs and CALSSA that thermal overloads, customer energization and interconnection delays, system peak loading, and voltage deviations are appropriate distribution-system constraints for IOUs to consider addressing through DER orchestration. The Commission also agrees with SCE and SDG&E that deferral of distribution investments is a potential operational benefit of DER orchestration. As discussed in more depth below, the Commission agrees with Cal Advocates that IOU DER orchestration applications should provide net ratepayer benefits per use case.

The Commission directs the IOUs to define and justify the grid services that DERs will provide, such as reliability, outage mitigation/avoidance, infrastructure deferral, and electrification support, in the formal application for DER orchestration this decision directs. The IOUs must link each service to specific system and/or distribution needs and provide a justification for how these needs were identified. IOUs must also identify where DER flexibility can provide dependable distribution capacity and whether grid-utilization analysis can be used to identify locations where DER orchestration can effectively address distribution-system needs. Where an IOU proposes to rely on DER capacity for distribution planning, the application should identify the performance and reliability criteria DERs must satisfy and explain how dependable DER capacity would be represented in distribution planning. The IOUs should also explain

[42] AEU Opening Comments on March 23 Ruling at 13.

how demonstrated DER capacity could affect the need, timing, or sizing of traditional distribution investments.

4. DER Orchestration Application Framework

4.1. Framework Guiding Principles

The March 23 Ruling asked parties whether the Commission should adopt specific guiding principles, whether any guiding principles should be added, removed, modified, or clarified, and whether there should be opportunities to refine the guiding principles in subsequent proceedings reviewing IOU applications. The March 23 Ruling proposed the following 10 guiding principles for IOU DSO-led DER orchestration:

- 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; and
- Preventing double compensation.

SDG&E, CalCCA, CAISO, Nexamp, EnergyHub, CALSSA, UCAN, Universal Devices, EDF, and CA Efficiency + Demand Management Council generally support the proposed guiding principles with modifications or additions.[43]

[43] SDG&E Opening Comments on March 23 Ruling at 8, CalCCA Opening Comments on March 23 Ruling at 12, CAISO Opening Comments on March 23 Ruling at 13, Nexamp Opening Comments on March 23 Ruling at 4, EnergyHub Opening Comments on March 23 Ruling at 3,

Footnote continued on next page.

CAISO, PG&E, and SDG&E support adding reliability as a new guiding principle or modification to one of the listed guiding principles.[44] CalCCA recommends the addition of six guiding principles: "nondiscriminatory market access, operations, and dispatch," "independent monitoring and oversight of DSO and market functions," "optimization of existing grid capacity before authorization of capital investments," "competitive neutrality of DSO and marketplace operator," "fair compensation for flexibility services," and "timely access to accurate customer usage, DER, ICA, and grid data."[45] UCAN recommends the addition of "fostering third-party competition and market access" and "protocol neutrality and scalability."[46] Universal Devices recommends the addition of "local resilience and edge operability" and notes that "technology-neutral, performance based" should be explicitly extended to the communications protocol layer.[47] Nexamp recommends adding "DER integration with pro-active grid plan updates" and "non-wires alternatives" as principles.[48] AEU recommends adding "realizing the maximum cost-effective potential of DER resources" and "promoting competition and liquidity in the

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CALSSA Opening Comments on March 23 Ruling at 4, UCAN Opening Comments on March 23 Ruling at 2, Universal Devices Opening Comments on March 23 Ruling at 3, EDF Opening Comments on March 23 Ruling at 7, CA Efficiency + Demand Management Council Opening Comments on March 23 Ruling at 8.

[44] CAISO Opening Comments on March 23 Ruling at 13, PG&E Opening Comments on March 23 Ruling at 5, SDG&E Opening Comments to March 23 Ruling at 9.

[45] CalCCA Opening Comments on March 23 Ruling at 12.

[46] UCAN Opening Comments on March 23 Ruling at 3.

[47] Universal Devices Opening Comments on March 23 Ruling at 3.

[48] Nexamp Opening Comments on March 23 Ruling at 4.

market."[49] EnergyHub opposes strict technological neutrality and believes interoperability is not currently a major barrier.[50]

SBUA and 350 Bay Area recommend providing additional specificity on certain principles, including the distinction between "ratepayer benefit and protection" and "equity and customer protection."[51] Cal Advocates recommends the Commission clarify several items and prioritize ratepayer benefit and protection, locational and temporal value recognition, and incremental evidence-based implementation in the guiding principles.[52] CalCCA suggests the Commission should establish guiding principles before deciding on a DSO framework.[53] CBD and 350 Bay Area concur that the Commission should establish guiding principles and a framework of functional roles and responsibilities for the DSO that are independent of the entity that performs the DSO roles and functions.[54] CALSSA cautions that guiding principles should add implementation efficiency and consistency, not slow program development.[55]

SDG&E, EDF, and CA Efficiency + Demand Management Council support the modification and refinement of guiding principles in proceedings where IOU applications are being reviewed.[56] Nexamp opposes refining guiding principles

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[49] AEU Opening Comments on March 23 Ruling at 14.

[50] EnergyHub Opening Comments on March 23 Ruling at 3.

[51] SBUA Opening Comments on March 23 Ruling at 2, 350 Bay Area Opening Comments on March 23 Ruling at 5.

[52] Cal Advocates Opening Comments on March 23 Ruling at 10.

[53] CalCCA Opening Comments on March 23 Ruling at 11.

[54] CBD and 350 Bay Area Joint Reply Comments on March 23 Ruling at 3.

[55] CALSSA Opening Comments on March 23 Ruling at 4.

[56] SDG&E Opening Comments on March 23 Ruling at 9, EDF Opening Comments on March 23 Ruling at 8, CA Efficiency + Demand Management Council Opening Comments on March 23 Ruling at 8.

during the review of each IOU application in the interest of time and consistency.[57]

The Commission agrees with CalCCA, CBD, and 350 Bay Area that adopting guiding principles prior to the filing of a Joint IOU Application will allow for a more efficient and streamlined process for the IOUs to develop their joint DER orchestration framework application. Accordingly, the Commission adopts the 10 guiding principles proposed in the March 23 Ruling with the following addition. The Commission agrees with SDG&E's suggestion of adding "safe and reliable grid operation" as a guiding principle. Reliability was also emphasized by PG&E and CAISO, and this phrasing will ensure that safety is included as a guiding principle.

The Commission declines to adopt suggestions to modify and refine guiding principles in proceedings where IOU applications are being reviewed. Guiding principles must be established up-front to create consistency and protect public policy interests during development of IOU applications, as suggested by Nexamp. However, in order to further refine the guiding principles adopted in this decision, a working group meeting series facilitated by the IOUs' consultant[58] shall occur prior to the Joint IOU Application filing before the Commission. This working group meeting series shall allow for a more detailed development of the guiding principles, how the principles will be implemented in a common format among the IOUs, and where there may be areas that require individual IOU approaches that can support achieving an overall common DER orchestration framework across the IOUs over time. The consultant shall prepare

[57] Nexamp Opening Comments on March 23 Ruling at 4.

[58] Gridworks facilitated the FGS workshop series and prepared the FGS Report.

a report within 10 months of the issuance of this decision that will be included as part of the Joint IOU Application to be filed with the Commission within 12 months of the issuance of this decision.

Accordingly, this decision adopts, with further refinements to occur through the working group meeting series, the 10 guiding principles proposed in the March 23, 2026 Ruling with these modifications:

- "Net" is added before ratepayer benefit to emphasize the importance of creating ratepayer savings greater than the cost of implementing DER orchestration; and
- "and protection" is removed from net ratepayer benefit as protection is already included in another principle, equity and consumer protection.

Further, we add the following guiding principle:

- Safe and reliable grid operation.

4.2. Pre-Application Stakeholder Engagement

The March 23 Ruling proposed a hybrid procedural approach consisting of two Commission-led workshops to develop the record on key technical, operational, and framework issues followed by formal IOU applications to develop and operationalize comprehensive DER Orchestration proposals. The Ruling also contemplated that the workshops and party comments could identify whether additional workshops, working groups, or other stakeholder processes would be useful before or during the application process.

The May 21, 2026 DER Orchestration Workshop and June 5, 2026 TSO-DSO Coordination Workshop substantially developed the record on the issues identified in the March 23 Ruling. Parties generally supported continued stakeholder engagement but differed on how much additional framework development should occur before application filing. Cal Advocates recommended a Commission-led working group to establish common framework requirements before applications.[59] PG&E supported continued stakeholder collaboration and workshops to refine issues that would evolve through implementation experience.[60] Other parties proposed various time-limited working group or workshop processes, while also emphasizing the need to avoid open-ended pre-application development.[61]

4.2.1. Working Group Meeting Series

The Commission will require an additional working group meeting series prior to the filing of a Joint IOU Application. The two Commission-led workshops, workshop reports, and subsequent party comments provide record to support for additional work in developing common framework requirements before the IOUs file an application. CBD and 350 Bay Area comment that the Commission should establish a framework of functional roles and responsibilities for the DSO that are independent of the entity that performs the DSO function, and we find that a working group series will enable discussions to support the development of this framework with contributions from multiple stakeholders.

The working group meeting series shall address the substantive issues this decision directs to be included in the IOUs' joint application. This includes the following:

- Guiding principles refinement;
- Valuation frameworks;
- Cost effectiveness and benefit-cost methodologies;
- Interoperability, DSO visibility, and dispatch and control;

[59] Cal Advocates Opening Comments on July 9 Ruling at 2-4

[60] PG&E Opening Comments on July 9 Ruling at 7-9

[61] CALSSA Reply Comments on July 9 Ruling at 7-8

- Role of DER aggregators;
- Flexible dispatching mechanisms;
- IOU technical readiness;
- Ownership of technology;
- Phased implementation and deployment;
- DER orchestration and real-time pricing.

This work shall consist of a series of meetings to be facilitated through a working group meeting series outside of this proceeding and does not need to be conducted as part of an open proceeding. The working group is to be opened to interested parties. Relevant information, including meeting dates and times, are to be served on the service list for this proceeding. A report shall be developed based on the working group meeting series with recommendations regarding each of the substantive issue areas addressed in this decision and listed above. If no consensus is reached toward one recommendation, the report may identify multiple options for recommendations. The working group report shall identify areas of stakeholder agreement and disagreement and provide recommendations or options to inform the Joint IOU Application.

The work of the group, including preparing a final report to be included with the Joint IOU Application, is to be completed within 10 months from issuance of this decision. The IOUs must allow parties to this proceeding to provide informal comments on the draft report within those 10 months. The final report is then to be included as part of the Joint IOU Application to be filed within 12 months of the issuance of this decision.

The Commission also finds value in providing stakeholders an opportunity to review the IOUs draft proposals prior to filing. Accordingly, in addition to or as part of to the working group meeting series described above, the IOUs shall convene one joint pre-application workshop to present their draft application and gather stakeholder feedback. This joint pre-application workshop shall occur after the draft report of the working group has been issued and before the Joint IOU Application is filed with the Commission.

The IOUs, in consultation with Energy Division and the IOUs' consultant leading the working group, may either jointly or individually conduct other public engagement opportunities such as follow-up workshops or webinars to continue to inform the development of their application framework as needed. These engagement opportunities should be coordinated with and through the working group effort described above, but would not be limited to working group members. These opportunities, led by the IOUs, would provide an opportunity for the IOUs to present how they envision applying the feedback discussed in the working group on topics such as operational requirements, stakeholder roles and responsibilities, and other framework requirements established in this decision and developed through the working group. The information discussed in the IOU engagements would be gathered and incorporated into the working group framework development to avoid delaying the application filing deadline established by this decision.

The working group meeting series is intended to streamline the application process and provide an effective and consistent foundation for the joint application and is not intended to slow down progress with developing the DER orchestration framework.

5. Valuation Frameworks

The March 23 Ruling asked parties to comment on appropriate valuation frameworks to quantify ratepayer value to potentially be unlocked through DER orchestration.

Many parties note that a valuation framework should include location-specific distribution benefits. UCAN emphasizes that the value of DER flexibility is highly location dependent.[62] Cal Advocates proposes a strict, granular, and comparison-based approach that uses location, use case, and time-specific valuation.[63] SDG&E supports using the California Standard Practice Manual cost-effectiveness framework, expanded to include DER-specific costs and locational/operational value.[64]

Several parties note that avoided costs should be included in a valuation framework. SDG&E specifies that avoided transmission, distribution, and generation costs should be included in a valuation framework.[65] UCAN recommends using the Avoided Cost Calculator (ACC) together with a robust LNBA to quantify DER orchestration value.[66] Similarly, AEU recommends pairing the current avoided cost framework for DERs with a transparent market framework that allows for DERs to bid into providing grid services.[67]

350 Bay Area and EDF oppose using the ACC in its current version to value DERs and recommend taking a more comprehensive approach that incorporates broader distribution system and societal benefits.[68] CalCCA emphasizes that any valuation framework should include societal and equity

[62] UCAN Opening Comments on March 23 Ruling at 3.

[63] Cal Advocates Opening Comments on March 23 Ruling at 8.

[64] SDG&E Opening Comments on March 23 Ruling at 7.

[65] *Id.* at 8.

[66] UCAN Opening Comments on March 23 Ruling at 3.

[67] AEU Opening Comments on March 23 Ruling at 14.

[68] 350 Bay Area Opening Comments on March 23 Ruling at 4, EDF Opening Comments on March 23 Ruling at 5.

benefits and suggests the Commission explore the UK Ofgem framework.[69] EDF highlights the potential use of distribution locational marginal pricing (DLMP) and advanced modeling (DSO+T frameworks) to quantify total system cost savings and broader social benefits.[70]

PG&E recommends a valuation framework that prioritizes ratepayer benefits, including affordability and customer energization speeds.[71] SCE agrees with valuing orchestration through energization speeds and affordability, and adds operational savings and deferred capital investments to their recommended valuation metrics.[72] Nexamp also supports valuing orchestration based on verifiable outcomes such as deferred utility system upgrades, reduced peak demand charges, constraint relief, reliability support, outage mitigation, and adherence to dispatch/curtailment signals.[73]

The Commission agrees with Cal Advocates, SDG&E, UCAN, SCE, and Nexamp that valuation of DER orchestration should reflect the specific use case and measurable benefits provided. The Commission also agrees with SDG&E and UCAN that valuation should account for locational benefits and differentiate, where applicable, between broader system-level benefits and location-specific distribution system benefits. Measurable, avoided, or deferred infrastructure costs and operational benefits should also be reflected where applicable, including the potential for DER orchestration to affect the need, timing, or sizing of traditional distribution investments.

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[69] CalCCA Opening Comments on March 23 Ruling at 14.

[70] EDF Opening Comments on March 23 Ruling at 5.

[71] PG&E Opening Comments on March 23 Ruling at 3.

[72] SCE Opening Comments on March 23 Ruling at 4.

[73] Nexamp Opening Comments on March 23 Ruling at 4.

It is premature for the Commission to order that the ACC be used as a tool for valuating DER orchestration programs at this time. The working group may propose the ACC as a tool, but given the lack of alignment among parties over how the ACC should be incorporated and which tools it should be combined with, the working group should include a discussion of how the ACC could combine with other tools and methods of quantifying more granular locational value of DER orchestration, as well as examine the valuation frameworks recommended by parties in this Track of the proceeding. The working group report should provide a recommendation or recommended options and the rationale for each recommendation as to the valuation framework to be included in the Joint IOU Application.

The Commission also agrees with CalCCA that equity benefits are relevant to the valuation of DER orchestration. The record does not establish a verifiable methodology for assigning monetary value to these benefits. However, the working group should include a discussion of equity, and the IOUs should include in their application a qualitative discussion of equity benefits that may result from proposed DER orchestration activities, where appropriate.

Accordingly, the Commission directs the working group to explore equity benefits and the IOUs to justify in its formal DER orchestration application the valuation methodology and metrics it proposed to use to assess the benefits of proposed DER orchestration use cases. The proposed approach must account for the specific use case and, where applicable, its location and timing; differentiate between broader system-level and location-specific distribution-system benefits; and identify measurable avoided or deferred infrastructure costs and operational benefits. The working group may examine the ACC, LNBA, or other valuation tools identified in the record but must explain why their selected options for tools and methodologies are appropriate for the DER orchestration use cases being evaluated, how they capture relevant locational and distribution-system value, and how they appropriately balance costs and benefits to ratepayers.

5.1. Cost-Effectiveness and Benefit-Cost Methodologies

The March 23 Ruling asked parties to comment on potential cost-effective mechanisms or measures that could be included as part of the proposed DER orchestration framework to demonstrate a net benefit to ratepayers. Parties were also asked to comment on potential benefit-cost methodologies for applications.

5.1.1. Use-Case Specific Approach to Cost-Effectiveness

Several parties emphasize that the net benefits of DER orchestration should be demonstrated through measurable outcomes and specific use cases, not theoretical aspirational benefits.[74] Cal Advocates argues that benefit-cost methodologies should be use case- and location-specific, and include measurable benefits such as avoided costs and full incremental costs.[75] PG&E recommends starting with a custom benefit-cost analysis per project with potential to standardize over time.[76] Similarly, SCE recommends a pilot and study-based approach under real conditions.[77] CALSSA suggests that cost-effectiveness data should come from targeted programs in high-value urban areas where grid constraints and upgrade costs are highest.[78] While SBUA emphasizes prioritizing

[74] PG&E Opening Comments on March 23 Ruling at 14, SBUA Opening Comments on March 23 Ruling at 4.

[75] Cal Advocates Opening Comments on March 23 Ruling at 19.

[76] PG&E Opening Comments on March 23 Ruling at 14.

[77] SCE Opening Comments on March 23 Ruling at 8.

[78] CALSSA Opening Comments on March 23 Ruling at 10.

implementation-ready approaches with near-term measurable results, CALSSA notes that benefit-cost analysis should use broader, longer-term regional scenarios covering multiple substations to capture system-level planning value.[79]

5.1.2. Measures for Demonstrating Cost-Effectiveness

350 Bay Area emphasizes customer affordability as a critical measure for cost-effectiveness.[80] SBUA similarly argues that benefit-cost analysis should reflect customer affordability pressures.[81] Universal Devices urges that aggregator transaction costs must be included as an explicit cost category, along with customer hardware, BTM platform/aggregator software fees, aggregator margin on transactions, IOU distributed energy resource management system (DERMS)/advanced distribution management system (ADMS) integration costs per model, and edge resilience capability cost.[82]

Several parties support including non-energy benefits in a cost-effectiveness evaluation. CalCCA recommends evaluating societal benefits in DER orchestration cost-benefit analysis.[83] 350 Bay Area emphasizes the importance of accounting for environmental impacts and health burdens.[84] EDF supports incorporating qualitative non-energy benefits such as resilience and

[79] SBUA Opening Comments on March 23 Ruling at 4, CALSSA Opening Comments on March 23 Ruling at 10.

[80] 350 Bay Area Opening Comments on March 23 Ruling at 11.

[81] SBUA Opening Comments on March 23 Ruling at 4.

[82] Universal Devices Opening Comments on March 23 Ruling at 5-6.

[83] CalCCA Opening Comments on March 23 Ruling at 20.

[84] 350 Bay Area Opening Comments on March 23 Ruling at 11.

avoided outages.[85] EDF and 350 Bay Area both support the Total Resource Cost Test and Societal Cost Test as evaluation tools to capture non-energy benefits.[86]

The Commission agrees with Cal Advocates that benefit-cost methodologies proposed in the Joint IOU Application should evaluate costs and benefits at the use-case level and account for location-specific impacts where applicable. The Commission also agrees with Cal Advocates that benefits should be measurable, including avoided costs where applicable, and with Universal Devices that the costs necessary to implement and operate DER orchestration should be reflected in the analysis. Together, these requirements will allow the Commission to evaluate whether individual DER orchestration use cases provide net benefits to ratepayers based on measurable benefits and the full incremental costs necessary to provide those services.

The Commission recognizes 350 Bay Area’s and SBUA's concerns regarding customer affordability. Ratepayer impacts are relevant to determining whether DER orchestration provides net ratepayer benefits; however, the Commission declines to establish a separate affordability test for evaluating DER orchestration cost-effectiveness.

The Commission also finds that broader deployment of DER orchestration use cases should be supported by demonstrated performance, reliability, and cost-effectiveness, and the IOUs should propose measurable criteria for determining when a use case is ready to move from demonstration to broader deployment. Accordingly, the Commission directs the working group report and the formal Joint IOU Application to propose potential cost-effective mechanisms

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[85] EDF Opening Comments on March 23 Ruling at 14.

[86] EDF Opening Comments on March 23 Ruling at 14, 350 Bay Area Opening Comments on March 23 Ruling at 11.

or measures that could be included as part of a DER orchestration framework to demonstrate a net benefit to ratepayers. Proposed methodologies must evaluate cost-effectiveness at the use-case level, account for location-specific costs and benefits where applicable, and compare measurable benefits, including applicable avoided costs, against the full incremental costs necessary to implement and operate each use case.

6. Interoperability, DSO Visibility, Dispatch and Control

A key component of the DER orchestration framework that the IOUs are directed to propose in the joint application will center on DER visibility to the DSO as well as DER dispatchability and control. Interoperability supports all three of those functions.

PG&E and SCE explain this issue at length:

> While some limited communication with DERs is possible today, this is a significant barrier that needs to be addressed. On the utility side, IOUs are in the process of deploying their DERMS to enable granular two-way communication with DERs, either individually or via an aggregator . . . In the context of interoperability, aggregators and Original Equipment Manufacturers (OEMs) should have a robust set of rules and requirements allowing for DER orchestration (awareness and dispatchability) with DERMS.[87]

Current communication barriers limit the ability of BTM DERs to provide grid services and also reduce program cost-effectiveness and may exclude customers from participating in beneficial programs.[88] Reliance on proprietary

[87] PG&E & SCE Opening Comments on October 17 Ruling at 16-17.

[88] UCAN Opening Comments on October 17 Ruling at i and CalCCA Opening Comments on October 17 Ruling at 5.

OEM systems introduces unnecessary costs, operational risks, and interoperability challenges.[89]

6.1. IOU Presentations on Proposed Strategies for Interoperability

The March 23 Ruling asked whether the IOUs should present their proposed strategy for achieving interoperability in proposed applications, including communications protocols, to enable scalable DER orchestration.

PG&E, SCE, SDG&E, Universal Devices, Nexamp, EDF, CA Efficiency + Demand Management Council, and 350 Bay Area support IOUs presenting on their proposed strategy for achieving interoperability in their DER orchestration applications.[90]

PG&E proposes standardized protocols such as IEEE 2030.5 for communications to help achieve interoperability.[91] SCE similarly states that its "DERMS supports IEEE 2030.5/CSIP for its reliability, cybersecurity, and fail-safe functionalities. SCE has made clear on the Track 3 record that it believes IEEE 2030.5 is the key to scaling DER orchestration."[92] SDG&E states that its Grid Modernization Plan presents SDG&E's position on communication protocols.[93]

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[89] VGIC Opening Comments on October 17 Ruling at 6.

[90] PG&E Opening Comments on March 23 Ruling at 11, SCE Opening Comments on March 23 Ruling at 7, SDG&E Opening Comments on March 23 Ruling at 16, Universal Devices Opening Comments on March 23 Ruling at 4, Nexamp Opening Comments on March 23 Ruling at 7, EDF Opening Comments on March 23 Ruling at 11, CA Efficiency + Demand Management Council Opening Comments on March 23 Ruling at 10, 350 Bay Area Opening Comments on March 23 Ruling at 9.

[91] PG&E Opening Comments on March 23 Ruling at 11.

[92] SCE Opening Comments on March 23 Ruling at 7.

[93] SDG&E Opening Comments on March 23 Ruling at 16.

Comments by non-IOU parties converge on open architecture and third party participation.[94] Several parties note that proposed interoperability and communication strategies should be flexible and non-proprietary to encourage DER participation.[95] 350 Bay Area emphasizes that communication and interoperability strategies should be reviewed by stakeholders.[96] CALSSA, SCE, Universal Devices, and EDF recommend building interoperability and communication strategies based on existing standards such as IEEE 2030.5.[97] However, Universal Devices also urges that a DER orchestration framework not mandate IEEE 2030.5 as an exclusive signal protocol that would exclude the majority of deployed residential BTM devices and the aggregators that currently serve them via OpenADR.[98] Universal Devices is concerned about vendor lock-in, arguing that "a framework built around a single signal type or a single utility's proprietary implementation, rather than an open, plugin-based execution layer, risks locking ratepayers, manufacturers, and the Commission into a small number of vendors, with attendant risks to cost, competition, and long-term flexibility."[99]

AEU opposes the IOUs presenting on their proposed interoperability strategy in their DER orchestration applications and believes the Commission

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[94] UCAN Reply Comments on March 23 Ruling at 2.

[95] CalCCA Opening Comments on March 23 Ruling at 19, UCAN Opening Comments on March 23 Ruling at 4-5, EDF Opening Comments on March 23 Ruling at 11, 350 Bay Area Opening Comments on March 23 Ruling at 9.

[96] 350 Bay Area Opening Comments on March 23 Ruling at 9.

[97] CALSSA Opening Comments on March 23 Ruling at 9, SCE Opening Comments on March 23 Ruling at 7, Universal Devices Opening Comments on March 23 Ruling at 4, EDF Opening Comments on March 23 Ruling at 10.

[98] Universal Devices Reply Comments on March 23 Ruling at 4.

[99] Universal Devises Opening Comments on July 9 Ruling at 2-3.

should establish consistent statewide standards for interoperability.[100] Universal Devices supports this position and states that the BTM execution layer in particular needs consistent statewide standards.[101] SDG&E cautions that interoperability is not fully within IOU control and will remain costly or limited without broader state action.[102] CalCCA emphasizes a need to ensure cost-effective interoperability and cautions against reliance on complex IOU ADMS/DERMS platforms with specific communication protocols that will limit DER participation.[103]

The working group is to address the following items that the Commission directs the Joint IOU application for DER orchestration to specify (i) what information should be shared as part of the orchestration plan; (ii) with whom; (iii) with what required granularity/cadence/latency; and (iv) with what privacy/cybersecurity safeguards. The Commission agrees generally with Universal Devices that the IOUs should propose open, standardized, and interoperable communication protocols that reduce reliance on proprietary OEM clouds and enable grid-edge innovation. This position balances the IOUs' priority of cybersecurity and reliability with non-IOU convergence on open-access standards. As such, we direct the IOUs to propose in their application the use of open, standardized, and interoperable communication protocols, and direct that any deviation from this directive includes justification for why no open, standardized, and interoperable communication protocols will meet the proposed needs.

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[100] AEU Opening Comments on March 23 Ruling at 17.

[101] Universal Devices Reply Comments on March 23 Ruling at 5.

[102] SDG&E Opening Comments on March 23 Ruling at 16.

[103] CalCCA Reply Comments to March 23 Ruling at 7.

The Commission also directs the IOUs to address communication barriers in their applications, which include but are not limited to: excessive access fees, limited functionality, and vendor lock-in that can undermine DER program cost-effectiveness and ratepayer value. Accordingly, the IOU application should establish pathways for secure, resilient communication and continuity of grid services, including safeguards in the event of technology provider failures or market exits. These measures ensure that DSO-led DER orchestration maintains DER visibility to the DSO as well as DER dispatchability and control.

The Commission also directs the IOUs to identify in the application existing systems and capabilities that can support DER orchestration, additional capabilities needed to implement their proposals, and a description of how their proposed architecture reflects their technical and operational readiness. While the proposal for the framework must be common across the IOUs, we acknowledge that each IOU is at a different stage of technical and operational readiness. As such, the joint application must also include sections describing each IOUs' plan and timeline for implementation to ultimately implement the common framework. This decision directs the IOUs to distinguish between existing and previously authorized capabilities from proposed new investments. Finally, this decision directs the IOUs to continue TSO-DSO coordination with CAISO during the application proceeding and incorporate relevant developments regarding DER visibility, data exchange, service prioritization, and operational coordination into the application record.

6.2. Role of DER Aggregators Within a Proposed Framework

Parties differ on how IOU applications should address the role of DER aggregators within a DER orchestration framework. In this proceeding, the term "aggregator" applies to a third-party technical service provider who aggregates and operates DER programs on behalf of individual DER owners.[104]

Nexamp and UCAN suggest that proposed applications treat aggregators as core participants on a comparable or co-equal basis to IOUs.[105] EDF explains that DER aggregators will play a critical role in scaling DER orchestration because utilities are unlikely to directly manage millions of customer devices cost-effectively.[106] CALSSA takes a stronger stance that aggregators should be the primary operators of DER fleets because energy storage providers have been refining their algorithms for balancing grid services and customer needs and expectations since the Commission launched the now-concluded Demand Response Auction Mechanism in 2014.[107]

Other parties view aggregators as a smaller component of DER orchestration. Universal Devices views the role of aggregators as optional competitive service providers, not mandatory intermediaries.[108] PG&E suggests aggregators provide coordinated DER services while utilities retain responsibility for system reliability and operational control.[109] PG&E further suggests that aggregator participation should require clear performance standards tied to specific grid services.[110] EnergyHub states that aggregators are not inherently necessary or entitled to a role within a DER orchestration

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[104] SCE Opening Comments on March 23 Ruling at 10.

[105] Nexamp Opening Comments on March 23 Ruling at 9, UCAN Opening Comments on March 23 Ruling at 5.

[106] EDF Opening Comments on March 23 Ruling at 15.

[107] CALSSA Opening Comments on March 23 Ruling at 11.

[108] Universal Devices Opening Comments on March 23 Ruling at 6.

[109] PG&E Opening Comments on March 23 Ruling at 15.

[110] *Ibid.*

framework due to the potential for additional administrative complexity and cost.[111]

SCE believes it is premature to define aggregators' full role until program design and cost-benefit outcomes become clear.[112] CalCCA argues that the DSO framework should aim to maximize DER participation and rejects IOU suggestions that the Commission limit the role of aggregators in DER orchestration.[113]

Parties generally align on aspects of aggregator participation that should be defined in an IOU application. Parties mention non-proprietary open data exchange,[114] performance standards,[115] and accountability mechanisms that include consequences for non-delivery.[116] PG&E highlights that "participation by aggregators and other third parties must occur within a DSO-led operational framework that preserves clear accountability for system reliability and safety."[117] Universal Devices recommends requiring each IOU application to define a published timeline for an open aggregator interface, as PG&E's current DERMS aggregator interface is proprietary.[118]

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[111] EnergyHub Opening Comments on March 23 Ruling at 4.

[112] SCE Opening Comments on March 23 Ruling at 10.

[113] CalCCA Reply Comments on March 23 Ruling at 8.

[114] UCAN Opening Comments on March 23 Ruling at 4, AEU Opening Comments on March 23 Ruling at 19, CA Efficiency + Demand Management Council Opening Comments on March 23 Ruling at 12.

[115] PG&E Opening Comments on March 23 Ruling at 15, UCAN Opening Comments on March 23 Ruling at 5, CalCCA Opening Comments on March 23 Ruling at 22.

[116] CA Efficiency + Demand Management Council Opening Comments on March 23 Ruling at 12.

[117] PG&E Reply Comments on March 23 Ruling at 4.

[118] Universal Devices Opening Comments on March 23 Ruling at 7.

The Commission agrees with PG&E that participating aggregators should be subject to the same clear performance standards as IOUs, including clear accountability mechanisms. The Commission partially agrees with EnergyHub's assertion that aggregators should not necessarily be entitled to a role within DER orchestration, because when not clearly structured to add value, aggregators could add complexity and cost. However, the Commission also finds that aggregators may offer enhanced abilities to manage customer assets cost-effectively. Accordingly, this decision directs the working group and the IOUs in their application to carefully consider the role of DER aggregators in an orchestration framework and agrees with PG&E that aggregators should be allowed to provide coordinated DER services provided that the role of aggregators adds value, does not undermine the goal of cost-effectiveness, and does not introduce unnecessary complexity.

6.3. Flexible Dispatching Mechanisms

Several parties commented on mechanisms to complement DER orchestration by enabling DSOs to dispatch distribution-level flexibility services from DERs and aggregators.[119] These mechanisms can schedule and dispatch DER capacity available during specified time periods and at locations where distribution-system needs have been identified. As Clean Coalition explains, DER providers could offer capacity capable of operating during a specific time window at a needed grid location.[120]

CalCCA recommends the use of centralized platforms to complement IOU grid-edge DERMS and encourage third-party participation "by providing a

[119] DSO Orchestration Workshop Report on May 21, 2026 at 128.

[120] Clean Coalition Opening Comments on July 9 Ruling at 4.

centralized platform that more easily facilitates transactions between IOUs and flexibility providers."[121] CESA encourages the Commission to closely consider the risks and benefits associated with IOU-operated flexibility mechanisms as compared with independently operated mechanisms, as discussed by CalCCA during the May 21, 2026 workshop.[122] AEU suggests that a single, statewide platform for enabling DER flexibility with vendor-neutral governance should be a threshold parameter before authorizing formal IOU applications to proceed.[123]

The Commission agrees that DER orchestration should provide a structured means for dispatching distribution-level services from DERs. The Commission agrees with CESA that the governance implications of IOU-operated and independently operated flexibility mechanisms should be considered. However, the Commission declines at this stage to prescribe a particular structure or governance model. The Commission also declines to adopt AEU's proposal to require a single statewide platform before the Joint IOU application proceeds. However, the Joint IOU Application shall proposal a single or consistent proposal for the DER orchestration framework. These design and governance issues will be addressed and justified through the formal Joint IOU DER Orchestration Application.

Flexible dispatch must also be coordinated with the DSO's operational responsibilities. Operational coordination and dispatch processes must enable DSOs to schedule and activate DER flexibility in response to identified distribution-system needs, including local reliability, infrastructure deferral, and

[121] CalCCA Opening Comments on July 9 Ruling at 13.

[122] CESA Opening Comments on July 9 Ruling at 4, see Workshop Report CalCCA Presentation at 12-14.

[123] AEU Opening Comments on July 9 Ruling at 2.

outage mitigation needs, based on real-time and forecasted grid conditions. Proposed approaches should therefore address both how DER flexibility will be enabled and how resources will be coordinated and dispatched to match DER capabilities with identified distribution system needs.

Accordingly, the Commission directs the IOUs to propose and justify in the Joint IOU DER Orchestration Application a flexible dispatching mechanism that enables DERs to provide distribution grid services. The proposal must address participant eligibility, protections against double payment or double counting, and performance, measurement, and verification requirements. Each IOU must explain its individual plan for implementation, including how the proposed mechanism will schedule and dispatch DER flexibility based on identified distribution-system needs and describe the operational coordination, communications, and dispatch processes necessary to enable DERs to flexibly respond to DSO operational needs. The proposal must also explain how the mechanism provides open and nondiscriminatory participation for utility, community choice aggregator (CCA), energy service aggregator, and customer-managed DERs. Finally, the IOUs must identify the respective roles of utilities, aggregators, CCAs, customers, and other DER providers and address safeguards for competitive neutrality and appropriate Commission oversight.

7. DER Orchestration Implementation

7.1. IOU Readiness

The March 23 Ruling asked parties to comment on how the Commission should account for differing levels of readiness across IOUs to implement DER orchestration. Readiness refers to business and technology readiness across IOUs, including functionality and maturity of DERMS programs. Parties submitted comments on how future applications could demonstrate utility readiness, including the maturity of ADMS and DERMS platforms, dispatch capabilities, operational metrics, and organizational preparedness.

As EDF notes,

> "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."[124]

7.1.1. Current DER Orchestration Offerings

While IOUs are planning and implementing significant upgrades to their capabilities to operate distribution systems with high DER penetration,[125] the IOUs are still at varying stages of technological and operational readiness for DER orchestration. As EDF explains, "DERMS maturity and functionality varies significantly across the three IOUs."[126] As discussed in CALSSA's comments to the March 23 Ruling, PG&E and SCE have core DERMS capabilities, and SDG&E intends to build them as needed.[127]

PG&E deployed a DERMS in 2023 that is now actively sending commands to two energy storage systems being operated to help avoid distribution system upgrades.[128] SCE completed site acceptance testing and technical implementation of its phase 1 Base DERMS, which will be able to monitor and dispatch DERs.[129] SDG&E received spending authorization for a DERMS pilot in 2023.[130] At the

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[124] EDF Opening Comments on March 23 Ruling at 10.

[125] Gridworks, Future Grid Study Report at 36.

[126] EDF Opening Comments on March 23 Ruling at 10.

[127] CALSSA Opening Comments on March 23 Ruling at 7-8.

[128] *Id.* at 7.

[129] *Id.* at 6

[130] *Id.* at 7.

same time, all three IOUs are developing more advanced DERMS capabilities.[131] Varying readiness levels among IOUs should therefore be considered for scaling and implementation of DER orchestration.

7.1.2. Demonstrating IOU Readiness

PG&E, SDG&E, CalCCA, Nexamp, SBUA, and EDF support IOU applications addressing IOU readiness, including existing DERMS/ADMS functionality.[132] The IOUs generally agree that readiness should be assessed for each IOU individually, not based on uniform criteria across IOUs.[133] AEU and EDF disagree, recommending the Commission establish a consistent statewide framework for IOUs to individually progress toward.[134]

PG&E and SCE support evaluating IOU readiness based on technological and operational maturity, including ADMS and DERMS capability.[135] PG&E recommends a capability-based approach that encourages IOUs to advance toward common objectives instead of requiring all IOUs to meet a standard readiness threshold before implementation can begin.[136] SDG&E suggests demonstrating readiness through pilots and proven capabilities, including ability

[131] *Id.* at 8.

[132] PG&E Opening Comments on March 23 Ruling at 9, SDG&E Opening Comments on March 23 Ruling at 12, CalCCA Opening Comments on March 23 Ruling at 17, Nexamp Opening Comments on March 23 Ruling at 7, SBUA Opening Comments on March 23 Ruling at 3, EDF Opening Comments on March 23 Ruling at 10.

[133] PG&E Opening Comments on March 23 Ruling at 9, SCE Opening Comments on March 23 Ruling at 7, SDG&E Opening Comments on March 23 Ruling at 12.

[134] AEU Opening Comments on March 23 Ruling at 17, EDF Reply Comments on March 23 Ruling at 2.

[135] PG&E Opening Comments on March 23 Ruling at 9, SCE Opening Comments to March 23 Ruling at 7.

[136] PG&E Opening Comments on July 9 Ruling at 11.

to dispatch DERs in real operational conditions.[137] Cal Advocates states that general platform maturity and future capability claims are not sufficient, and IOU readiness should be shown through tested pilots and results.[138] Cal Advocates also highlights that IOUs should demonstrate the feasibility of customer and aggregator participation, and cost-effectiveness use cases.[139] CALSSA notes that existing IOU systems can already support dispatch, forecasting, and limited distribution services, and recommends prioritizing near-term program implementation over evaluating readiness.[140]

The Commission agrees with parties, such as SDG&E and Cal Advocates, that proposed applications should demonstrate IOU readiness, and that readiness should be assessed based on proven capabilities including tested pilots and results. We adopt the recommendation of AEU and EDF that the Commission establish a consistent statewide framework for IOUs to individually progress toward. As such, the Commission directs the IOUs to file a joint application with a proposed consistent statewide framework. However, we also see value in the IOUs' comments that readiness should be assessed for each IOU separately. As such, while we direct a consistent statewide framework, the Commission further directs the IOUs to include in their Joint DER Orchestration Application the utility-specific criteria by which each utility will demonstrate its technological and operational readiness to deploy DER orchestration efforts at scale, working towards the common framework. Although the state's three large electric IOUs are at different stages of readiness to deploy DER orchestration,

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137 SDG&E Opening Comments on March 23 Ruling at 15.

138 Cal Advocates Opening Comments on March 23 Ruling at 18.

139 *Ibid.*

140 CALSSA Opening Comments on March 23 Ruling at 6-8.

having a common statewide framework to progress toward will allow for better assessment of the benefits of the framework and provide better visibility overall as to demand side resources for the CAISO, customers, and third parties which in turn will result in economic benefits to ratepayers. Reflecting that situation, the Commission directs the working group to examine the IOUs' readiness for implementation of an orchestration framework and steps to create a statewide framework that is consistent with moving the deployment process forward in a timely manner taking into account where each IOU is in the process. IOUs currently have DERMS capabilities or plan to build them as needed. The Commission does not see a need to wait for each IOU to be at the same point of readiness to begin implementation of a process that is designed to incrementally develop a common statewide standard for DER orchestration framework.

7.1.3. Investments Required to Support DER Orchestration Implementation

The March 23 Ruling asked whether the proposed DER orchestration applications should identify additional technology investments required to support DER orchestration implementation.

PG&E, SDG&E, Nexamp, EnergyHub, 350 Bay Area, SBUA, and EDF all support the proposed applications identifying additional technology investments.[141] SDG&E notes that customer-side technologies will likely not be addressed in the application.[142] Nexamp states that proposed applications should distinguish between capabilities needed now versus later-phase

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[141] PG&E Opening Comments on March 23 Ruling at 16, SDG&E Opening Comments on March 23 Ruling at 18, Nexamp Opening Comments on March 23 Ruling at 9, EnergyHub Opening Comments on March 23 Ruling at 5, 350 Bay Area Opening Comments on March 23 Ruling at 13, SBUA Opening Comments on March 23 Ruling at 4, EDF Opening Comments on March 23 Ruling at 15.

[142] SDG&E Opening Comments on March 23 Ruling at 18.

upgrades.[143] EnergyHub emphasizes edge DERMS functionality as a technology investment that should be identified in proposed applications.[144] SBUA recommends consideration of non-technological investments required to effectively implement enhancements.[145]

SCE recommends the GRC as the preferred mechanism to propose technology-related investments.[146] Cal Advocates and AEU oppose the inclusion of additional technology investments in IOU applications and agree that the GRC is the appropriate forum for seeking recovery of broad technology investments.[147] UCAN urges the Commission to apply rigorous cost-effectiveness scrutiny to any utility proposals for new technology investments to support DER orchestration.[148] SBUA is similarly concerned about utility expenditures and the difficulty of controlling costs outside of GRC proceedings. SBUA agrees with Cal Advocates that the "Commission should avoid using DER orchestration as a backdoor justification for broad advanced metering infrastructure (AMI), DERMS, communications, or platform investments that should be reviewed in the GRC where the Commission and parties can review the costs requested in a more fulsome way."[149]

143 Nexamp, Inc. Opening Comments on March 23 Ruling at 9.

144 EnergyHub Opening Comments on March 23 Ruling at 5.

145 SBUA Opening Comments on March 23 Ruling at 4.

146 SCE Opening Comments on March 23 Ruling at 10.

147 Cal Advocates Opening Comments on March 23 Ruling at 23, AEU Opening Comments on March 23 Ruling at 20.

148 UCAN Opening Comments on March 23 Ruling at 6.

149 SBUA Reply Comments on July 9 Ruling at 4, quoting Cal Advocates Opening Comments on July 9 Ruling at 12.

The Commission agrees with SCE, Cal Advocates, AEU, UCAN, and SBUA that broad technology investments should generally be reviewed through the GRC or other applicable cost-recovery proceedings where the impacts of those investments can be properly evaluated. The Commission also agrees that DER orchestration should not serve as a basis for duplicative technology investments or funding that is already authorized or pending authorization in another proceeding.

Accordingly, this decision directs the IOUs to first leverage existing technology investment authorizations or pending technology investment authorizations to implement their DER orchestration framework before requesting any incremental technological investment in the application. If the IOUs seek any incremental technology investment authorization in their application, they must demonstrate why the funding cannot be leveraged from the GRC or other cost recovery proceedings. The Commission sets a high bar for approving any incremental technology investment to best protect ratepayers from unnecessary costs.

In the interim period between adoption of this decision and the conclusion of the DER orchestration framework application proceeding, the Commission recognizes that some incremental cost recovery may be needed to support the development of the joint application, including support for facilitating the working group and any minor studies to inform the development of the joint application. The IOUs must, to the greatest extent possible, leverage existing funding vehicles for these activities such as GRCs. If additional incremental funding is necessary, the IOUs must exercise judicious caution and seek recovery only for incremental costs to support the development of the application.

Accordingly, the IOUs may establish memorandum accounts to track incremental costs associated with administrative costs to prepare the application, consultant fees and administrative costs to support the working group, and minor studies to inform the development of the application. These costs must not exceed $500,000 across the three IOUs. Further, each IOU must justify any costs recorded in these accounts, as they will be subject to reasonableness review. Each IOU is authorized to submit a Tier 2 advice letter to establish a memorandum account within two months of the adoption date of this decision. The advice letter must explain why incremental cost recovery is necessary.

7.1.4. Predefining Ownership of Technology

The IOUs oppose requiring applicants to specify whether technological capabilities should be customer- or utility-owned.[150] PG&E argues that "requiring applicants to specify ownership models ex ante could unnecessarily constrain solutions and limit innovation."[151] SCE finds it unnecessary to further define ownership in IOU applications because ownership and cost allocation of proposed technology investments would already be transparent.[152] SDG&E also sees no need for ownership or cost breakdowns in IOU applications.[153]

CalCCA, Nexamp, and EDF support applications specifying whether technological capabilities should be customer- or utility-owned.[154] Nexamp supports ownership specification because "ownership and cost allocation

[150] PG&E Opening Comments on March 23 Ruling at 16-17, SCE Opening Comments on March 23 Ruling at 10, SDG&E Opening Comments on March 23 Ruling at 18.

[151] PG&E Opening Comments on March 23 Ruling at 16.

[152] SCE Opening Comments on March 23 Ruling at 10.

[153] SDG&E Opening Comments on March 23 Ruling at 18.

[154] CalCCA Opening Comments on March 23 Ruling at 23, Nexamp Opening Comments on March 23 Ruling at 9, EDF Opening Comments on March 23 Ruling at 16.

directly affect participation, interoperability, and whether DER orchestration delivers actual net ratepayer value."[155] EDF further supports applications evaluating which technologies could be either utility- or customer-owned, and the benefits of each ownership model.[156]

The Commission agrees that the Joint IOU Application should provide at a minimum general information as to the proposed source of funding for proposed technology investments or whether those investments would be customer- or utility owned as this information will be needed to assess the value and cost to ratepayers for the proposed orchestration framework.

7.2. Phased Implementation and Deployment

The March 23 Ruling asked parties to comment on whether the proposed DER orchestration applications should include a proposed phased implementation and deployment plan, and what elements the plan should contain.

PG&E, SCE, SDG&E, CalCCA, Nexamp, SBUA, EDF, and EnergyHub support proposed applications including a phased implementation and deployment plan.[157] EnergyHub stresses an incremental phased implementation approach with priority for scalable applications.[158] The IOUs propose a phased

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[155] Nexamp Opening Comments on March 23 Ruling at 10.

[156] EDF Opening Comments on March 23 Ruling at 16.

[157] PG&E Opening Comments on March 23 Ruling at 11, SCE Opening Comments on March 23 Ruling at 7, SDG&E Opening Comments on March 23 Ruling at 16, CalCCA Opening Comments on March 23 Ruling at 20, Nexamp Opening Comments on March 23 Ruling at 7, SBUA Opening Comments on March 23 Ruling at 4, EDF Opening Comments on March 23 Ruling at 12, EnergyHub Opening Comments on March 23 Ruling at 4.

[158] EnergyHub Reply Comments on March 23 Ruling at 1.

approach starting with pilots to inform operational readiness.[159] PG&E further suggests that "rather than delaying implementation until all outstanding policy questions have been resolved, the Commission should establish core guardrails and enable a pathway for targeted demonstration activities designed to generate operational experience."[160] SCE has several relevant planned demonstrations, pilots, and studies underway.[161] CalCCA recommends joint pilots between IOUs and CCAs to leverage existing CCA customer agreements and DERMS that can integrate with IOU systems.[162] CALSSA opposes continuing pilots and recommends focusing phased implementation on real programs launched in priority regions.[163]

Nexamp states that phased implementation plans, if included in IOU applications, should identify pilot locations and use cases; readiness and technology requirements (including ADMS/DERMS, data, communications, and interoperability); customer eligibility and participation pathways; performance metrics and evaluation criteria; a timeline for scaling from static/scheduled approaches to more dynamic orchestration; and clear decision points for expansion, refinement, or termination based on results."[164] SDG&E recommends

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[159] PG&E Opening Comments on March 23 Ruling at 11-12, SCE Opening Comments on March 23 Ruling at 7-8, SDG&E Opening Comments on March 23 Ruling at 16.

[160] PG&E Opening Comments on July 9 Ruling at 2.

[161] SCE Opening Comments on March 23 Ruling at 7. SCE's current demonstrations, pilots and studies include Industrial Demand Flexibility-Enabling Distribution Grid Autonomous Resilience (IDF-EDGAR) Demonstration, the Stability Improvement with DERs (SIDER) Demonstration, the Orchestrated Charging and Advanced Resiliency for Distribution (ORCHARD) Pilot, and the Behind the Meter Optimization of Load Technologies 2.0 (BOLTS 2.0) Study.

[162] CalCCA Opening Comments on March 23 Ruling at 20.

[163] CALSSA Opening Comments on March 23 Ruling at 10.

[164] Nexamp Opening Comments on March 23 Ruling at 7.

that the Commission define a standardized pilot-reporting template so that pilots are documented consistently across IOUs.[165]

Cal Advocates argues that the Commission does not yet have sufficient information to evaluate the merits of phased DER orchestration deployment by IOUs.[166] AEU suggests that phased implementation should be considered after the Commission has defined clear objectives regarding fundamental framework components and consistent statewide infrastructure, platforms, and processes.[167] Cal Advocates argues that phasing should be included in the GRC, not in a stand-alone IOU application.[168]

The Commission agrees with CALSSA that the IOUs should focus on phased DER orchestration program implementation and deployment in the Joint IOU Application rather than launch pilots or limited deployment programs. Developing a statewide comprehensive DER orchestration framework is a complex topic deserving of a dedicated proceeding through the formal application process. The application process will allow the IOUs to develop a comprehensive statewide process, while taking into account the capabilities of each utility and how each utility-specific implementation proposal will incrementally achieve operations under a consistent DER orchestration framework. It is important to have a dedicated proceeding in which the Commission can consider the proposals together, conduct workshops as necessary, and address implementation and cost recovery. The Commission agrees with AEU that the Commission should define clear objectives regarding

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165 SDG&E Opening Comments on July 9 Ruling at 6.

166 Cal Advocates Opening Comments on March 23 Ruling at 18.

167 AEU Opening Comments on March 23 Ruling at 18.

168 Cal Advocates Opening Comments on March 23 Ruling at 19.

fundamental framework components before authorizing phased DER orchestration implementation. We also agree with Cal Advocates that phasing should be included in the GRC, not in a stand-alone IOU application. Accordingly, this decision directs PG&E, SCE, and SDG&E to file a joint comprehensive DER Orchestration application that includes the foundation for a consistent statewide DER orchestration framework with IOU-specific proposals for design and implementation for incrementally achieving one consistent statewide DER orchestration framework within 12 months of the adoption of this decision.

7.3. Compatibility of DER Orchestration with Potential Rollout of Real-Time Pricing

The IOUs offer dynamic pricing that reflects the hourly variation in electricity costs due to changes in demand. The March 23 Ruling asked parties to comment on how DER orchestration can be complementary and compatible with real-time pricing.

PG&E, SCE, SDG&E, UCAN, CALSSA, Weave Grid, and Nexamp support DER orchestration and real-time (or dynamic) pricing remaining complementary but separate tools.[169] As PG&E explains, "real-time pricing is best suited for use cases where safe and reliable operation of the utility system isn't contingent upon voluntary customer action. DER orchestration is complementary to real-time pricing in that it delivers more precise, dispatchable, and firm load management that can be deployed against localized distribution and

[169] PG&E Opening Comments on March 23 Ruling at 15, SCE Opening Comments on March 23 Ruling at 8-9, SDG&E Opening Comments on March 23 Ruling at 17, UCAN Opening Comments on March 23 Ruling at 5, CALSSA Opening Comments on March 23 Ruling at 11, Weave Grid Reply Comments on March 23 Ruling at 2, Nexamp Opening Comments on March 23 Ruling at 8.

transmission grid needs."[170] SCE explains that its dynamic rate system is limited in its ability to target localized constraints, and DER orchestration is better positioned to defer investment in the distribution system.[171] SDG&E notes several beneficial interaction points between orchestration and real-time pricing, including the fact that DER orchestration planning must account for expected customer responses to pricing.[172]

EDF and 350 Bay Area discuss these interaction points by noting that DER orchestration, when coordinated with real-time pricing structures, could ensure that price signals and dispatch signals are aligned.[173] EnergyHub further explains the beneficial interaction between coordinated real-time pricing structures and DER orchestration as "dual optimization," ensuring that customers save money while maintaining grid reliability.[174] EnergyHub illustrates this concept by using the example of Edge-DERMS software adjusting device behavior based on grid reliability needs and real-time price signals.[175]

Cal Advocates argues that real-time pricing is not central to DER orchestration at this stage, and coordination should only be considered after further evaluation of pricing effectiveness.[176]

The Commission agrees that dynamic pricing and DER orchestration are complementary but distinct tools. Whereas dynamic pricing typically assigns

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170 PG&E Opening Comments on March 23 Ruling at 15.

171 SCE Opening Comments on March 23 Ruling at 9.

172 SDG&E Opening Comments on March 23 Ruling at 17.

173 EDF Opening Comments on March 23 Ruling at 14-15, 350 Bay Area Opening Comments on March 23 Ruling at 12-13.

174 EnergyHub Opening Comments on March 23 Ruling at 4.

175 *Ibid.*

176 Cal Advocates Opening Comments on March 23 Ruling at 22.

value through price signals based on system conditions, DER orchestration more directly targets specific system needs that vary by location and use case. The Commission also recognizes, consistent with SDG&E, EDF, 350 Bay Area, and EnergyHub, that dynamic pricing is closely related to DER orchestration and may inform aspects of its development. For example, customer responses to dynamic pricing may affect load patterns and the availability or timing of DER flexibility. Dynamic pricing may also influence the cost-effectiveness of specific DER technology deployment use cases or investments by customers to deploy specific DERs that could in turn affect the capabilities or value of a DER orchestration mechanism.

The record demonstrates sufficient interaction between the two to require the Joint IOU DER Orchestration Application to include consideration of dynamic pricing, where relevant, in the development of DER orchestration.

8. Track 1 DPEP Issues

8.1. Background

8.1.1. Electrification Impact Study Part 2 (EIS Part 2)

Pursuant to Code Section 218, each IOU is responsible for owning, controlling, operating, and managing the distribution system. As part of this role, the IOUs engage in an annual DPEP, which uses forecasts of future electricity demand and a historical load profile review to identify grid needs and to plan solutions to upgrade the grid. For each solution, an execution process creates the workplan and schedule and complete detailed project planning, design, permitting, and construction.

D.24-10-030 directed the large IOUs to conduct an Electrification Impact Study (EIS) Part 2 to estimate and assess the potential costs of meeting electrification needs under multiple mitigated scenarios.[177] This would then produce learnings that could be applied to each utility's DPEP to improve distribution planning to leverage the potential for load flexibility to reduce distribution infrastructure capital costs.

The EIS Part 2 estimates and assesses the potential impacts (e.g., potential costs of upgrading the primary and secondary distribution grid) of meeting electrification needs under multiple scenarios (Base Case, Equity, and Demand Flexibility). It includes scenarios that estimate a range of costs and resources required to address identified grid needs. The first scenario is the Base Scenario, which uses the 2023 California Energy Commission (CEC) Integrated Energy Policy Report (IEPR) Local Reliability forecast to model the distribution system impacts of DER integration. Another scenario, the Equity Scenario, forecasts the distribution system impacts of adopting DERs in "high-priority communities" (low income, disadvantaged, and Tribal) at equal rates as other communities, in contrast to the expected base case in which DERs are deployed at a slower pace in low-income, disadvantaged, and Tribal communities than other communities. Finally, the Demand Flexibility Scenario applies load flexibility modifiers to various DER and electrification technologies to assess possible reductions in needed infrastructure upgrades.[178] PG&E's Enhanced Demand Flexibility Scenario also considers the impact of load shedding, as does SDG&E's Demand Flexibility Scenario.

Because the EIS Part 2 includes mitigation strategies to avoid infrastructure upgrades, the question addressed in this proceeding is whether, and how, to

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[177] Under a contract with Energy Division, Kevala conducted an EIS Part 1 study, which was not formally adopted by the Commission.

[178] PG&E EIS2 at 20-21, SDG&E EIS2 at 6-9, SCE EIS2 at 6-9.

integrate the findings from the EIS Part 2 into the DPEP.[179] This decision determines which pieces of the EIS Part 2 are ready for integration into future distribution planning cycles.

8.1.2. Additional Procedural Background

On March 13, 2024, an ALJ ruling attached a Staff Proposal describing the standard DPEP process that is targeted in Track 1 of this proceeding, with the proposed goal of being more forward-looking in the DPEP process.[180] The ALJ ruling requested that the utilities produce a load flexibility assessment to examine how future load shapes resulting from a range of flexible load strategies could impact distribution planning such as controlling distribution upgrade costs.[181]

D.24-10-030 instructed the IOUs to file a draft EIS Part 2 study with a Base Case Scenario, Equity Scenario, and a Demand Flexibility Scenario by September 30, 2025, and to file the finalized EIS Part 2 report 120 days later. On January 22, 2025, an Assigned Commissioner's and ALJ ruling directed the IOUs to incorporate the load flexibility assessment required in the Staff Proposal into the Demand Flexibility Scenario in the EIS Part 2 study. The ruling also set a preliminary timeline for a workshop to be held on the initial EIS Part 2 assumptions, party comments, and comment incorporation. Finally, that ruling sought party comments on modifying the due date for the filing of the EIS Part 2 studies, proposing that the due date of the final reports be moved to 120 days after the original September 30, 2025, delivery date.

On January 28, 2026, the IOUs filed final drafts of their EIS Part 2 reports.

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[179] D.24-10-030 at 97.

[180] Staff Proposal at 25.

[181] *Id.* at 83.

On May 8, 2026, an Assigned Commissioners' Ruling (May 8 Ruling) sought party responses to questions about the possible use of the EIS Part 2 final reports in the DPEP.

On May 29, 2026, the IOUs, Cal Advocates, EDF, SBUA, VGIC, and CalCCA filed opening comments on the EIS Part 2 final reports. Clean Coalition filed their opening comments late on June 1, 2026, after filing a motion seeking permission to late-file comments. Permission was granted by the assigned ALJ on June 2, 2026.

On June 5, 2026, the IOUs, Clean Coalition, and UCAN submitted reply comments.

8.2. EIS Part 2 Findings and Learnings

The first two questions regarding the EIS Part 2 reports asked parties to assess general findings and learnings and how could these findings be incorporated into and used by the annual DPEP. The parties' answers are discussed below.

8.2.1. EIS Part 2 Findings

Parties were asked how findings from the EIS Part 2 should inform the yearly DPEP. All IOUs agree that the EIS Part 2 findings should not be fully incorporated into the yearly DPEP; however, in the Scenario Planning Framework resolution (Resolution E-5414), the IOUs noted that a Demand Flexibility scenario could not be incorporated into the DPEP at that time because the EIS Part 2 analysis was not yet available.[182] In comments, SDG&E explains

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[182] Joint Reply To Protest Of Advice Letter 4675-E: San Diego Gas & Electric Company, Southern California Edison Company, And Pacific Gas And Electric Company Tier 3 Advice Letter proposing a framework for implementation of Scenario-Based Planning pursuant to Ordering Paragraph 8 Of D.24-10-030 (p. 2)

that the DPEP and EIS Part 2 serve fundamentally different purposes[183] and contends that the DPEP relies on tested, real world, expectation-based forecasts whereas the EIS Part 2 is designed to explore hypotheticals.[184] SCE describes how the EIS Part 2 is based on simplified assumptions that enable the IOUs to evaluate a range of outcomes on a shorter timeline.[185] SCE also states that no refinement of the EIS Part 2 assumptions can replicate the rigor of the current DPEP framework because of the diverging purposes of each tool.[186]

PG&E proposes that rather than be fully integrated, the findings should instead be viewed as a directional tool to help guide the DPEP rather than as a direct input.[187] EDF supports this finding that while the insights are insufficient to be fully integrated, they should not be ignored.[188] SDG&E and SCE more pointedly state that the EIS Part 2 scenarios are too hypothetical or not investment grade enough to be integrated into the DPEP.[189] SCE states that an investment grade refers to an insight that is well crafted enough to influence a utilities' investment decisions.[190] Cal Advocates concurs with SDG&E that the EIS Part 2 and DPEP serve different purposes and that the findings therefore cannot be integrated.[191] SBUA argues that any forecasting should be

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[183] SDG&E Reply Comments on May 8 Ruling at 1.

[184] *Id*. at 2.

[185] SCE Reply Comments on May 8 Ruling at 1.

[186] *Id*. at 1.

[187] PG&E Opening Comments on May 8 Ruling at 1.

[188] EDF Opening Comments on May 8 Ruling at 2.

[189] SDG&E Opening Comments on May 8 Ruling at 29, SCE Opening Comments on May 8 Ruling at 1.

[190] SCE Opening Comments on May 8 Ruling at 1.

[191] Cal Advocates Opening Comments on May 8 Ruling at 2.

"circumspective" and that electrification must consequently proceed along pathways of "no regrets" and "least-regrets."[192] SDG&E notes additional limitations including excluded cost categories (distribution line segments, land acquisition, equity implementation costs) and the inherent uncertainty of a 15-year forecasting horizon.[193]

On the other hand, VGIC, CalCCA, and Clean Coalition argue that EIS Part 2 findings should be integrated into DPEP but disagree on when and how, as discussed later in this decision.[194] All three parties state that the EIS Part 2 finds that orchestrated DERs can reduce system costs and lower ratepayer burden.[195] VGIC believes those findings should be incorporated into the DPEP now,[196] while CalCCA suggests waiting until the assumptions underlying the findings are more mature and accurate.[197] Clean Coalition disagrees with the IOUs' characterizations of the EIS Part 2 as "not investment-grade" and believes the EIS Part 2 could still be used as a planning tool.[198] Clean Coalition suggests that rather than directly integrating the findings into the DPEP framework, the utilities should adopt a new "Energy Tetris" framework that folds DER considerations, among others, into DER planning.[199]

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[192] SBUA Opening Comments on May 8 Ruling at 2.

[193] SDGE Opening Comments on May 8 Ruling at 5.

[194] VGIC Opening Comments on May 8 Ruling at 3, CalCCA Opening Comments on May 8 Ruling at 2, Clean Coalition Opening Comments on May 8 Ruling at 2-3.

[195] *Ibid.*

[196] VGIC Opening Comments on May 8 Ruling at 3.

[197] CalCCA Opening Comments on May 8 Ruling at 4.

[198] Clean Coalition Opening Comments on May 8 Ruling at 4.

[199] *Id*. at 3.

This decision will specify which EIS Part 2 components should be integrated into the DPEP and overall, DER planning processes, as explained below.

8.3. Scenario Specific Findings and Assumptions

The May 8 Ruling asked parties how findings and assumptions from individual scenarios could inform different aspects of the DPEP.

8.3.1. Equity Scenario Findings

The Equity Scenario was developed by each utility to evaluate the costs and infrastructure needs required under conditions in which deployment of DERs is consistent between disadvantaged communities and other communities.[200] Each utility approached the design of the scenario slightly differently. For example, SDG&E built on the Base Case by applying hypothetical load modifiers that are intended to reflect targeted electrification efforts in underserved areas.[201] PG&E increased the total adoption of DERs instead of redistributing adoption patterns to create parity between community types.[202] SCE instead altered the adoption pattern without increasing total adoption to create equal DER adoption between communities.[203]

Parties were also asked to determine how findings from the Equity Scenario should inform the Commission's efforts to prevent delays of grid upgrades in disadvantaged communities.

SDG&E argues that the Equity scenarios only address impacts on the distribution system's peak loads, grid needs, and costs, not possible delays in

[200] SDG&E Final EIS Part 2 at 7.

[201] *Id*. at 5.

[202] PG&E Final EIS Part 2 at 21.

[203] SCE Final EIS Part 2 at 8.

constructing the grid upgrades that can mitigate identified grid needs, and therefore cannot be used to ensure that disadvantaged communities (DACs) do not experience unreasonable delays in necessary grid upgrades.[204] PG&E and SCE both agree that the Equity Scenario serves better as an avenue for exploring alternative policy futures rather than as a basis for investment decisions because of the reasoning stated by SDG&E above.[205] Cal Advocates echoes SDG&E's sentiments that the Equity Scenario is unconnected to the prevention of grid delays and service quality in DACs.[206]

SBUA does not directly address the prevention of delays but firmly supports SDG&E's approach to the Equity Scenario to incorporate "no regrets" and "least regrets" equity objectives.[207] EDF similarly does not address the Equity Scenario as it pertains to delays.[208] EDF instead states that investments are needed to match DER deployment in disadvantaged communities and that the investments hinge on policy changes.[209] Without the policy changes, EDF still suggests that the Commission work to keep implementation timelines even by requiring timeline reporting for each project.[210] Clean Coalition suggests the Commission direct the IOUs to identify candidate locations, informed by EIS Part

[204] SDG&E Opening Comments on May 8 Ruling at 2.

[205] SCE Opening Comments on May 8 Ruling at 2-3, PG&E Opening Comments on May 8 Ruling at 3-4.

[206] Cal Advocates Opening Comments on May 8 Ruling at 5.

[207] SBUA Opening Comments on May 8 Ruling at 5.

[208] EDF Opening Comments on May 8 Ruling at 3.

[209] *Ibid*.

[210] *Ibid*.

2 results, where DER portfolios can reduce or defer distribution upgrades and improve resilience particularly in communities where adoption has lagged.[211]

The Commission agrees with the positions of the IOUs, Cal Advocates, and SBUA that the study's Equity Scenario should not be integrated into the DPEP planning cycle, as these scenarios presume for the sake of analysis policies and programs that do not yet exist. However, the Commission also agrees with comments from EDF and Clean Coalition that investments in DER deployments in disadvantaged communities are needed, implementation timeline for projects is needed, and that the Commission should direct the IOUs to identify candidate locations where DER portfolios can reduce or defer distribution upgrades. The planning process can inadvertently leave out upgrades in DACs, which can result in poor investment and resilience in these communities. Accordingly, while this decision does not integrate the EIS Part 2 Equity Scenario findings into the DPEP process, we do direct the IOUs to identify candidate locations for DER investment in disadvantaged and ESJ communities and require project tracking for projects in disadvantaged and ESJ communities in the DPEP.

8.3.2. Demand Flexibility Scenario Assumptions

Each utility took a different approach to designing Demand Flexibility scenarios, but all were crafted to assess the potential reduced infrastructure capital costs if increased load flexibility options are adopted. Both SCE and PG&E use standard DER adoption assumptions that remain at typical planning levels but shift the load shape using the CEC's Enhanced Demand Flexibility tool.[212] On the other hand, SDG&E utilizes load shed and load shift assumptions

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[211] Clean Coalition Opening Comments on May 8 Ruling at 3.

[212] PG&E Opening Comments on May 8 Ruling at 21, SCE Opening Comments on May 8 Ruling at 9.

that were adopted by Energy + Environmental Economics (E3) from the Lawrence Berkeley National Laboratory California Demand Response Potential Study.[213] SDG&E also utilized electric vehicle load profiles developed by E3.

SCE also analyzes an alternative demand flexibility scenario that keeps all assumptions the same as in their normal demand flexibility scenario but expands it by assuming 100% customer participation for light-duty electric vehicles, medium- and heavy-duty electric vehicles, residential energy storage, and non-residential energy storage.[214]

Parties were then asked whether the underlying assumptions of the Demand Flexibility Scenario were supported by current data and therefore reliable enough to serve as inputs for forecast and infrastructure cost planning.

The three IOUs and Cal Advocates unanimously agree that without further refinement, the demand flexibility assumptions, as stated in the EIS Part 2, are not fit to be fully integrated into planning or the yearly DPEP. [215] SBUA supports this position.[216] The IOUs and Cal Advocates state that the demand flexibility assumptions are not yet reliable because of the lack of validated participation data at scale, the absence of approved programs that would drive sufficient DER enrollment in load flexibility, and the continued need for enabling infrastructure such as AMI 2.0 and DERMS.[217] In contrast, EDF, CalCCA and

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[213] SDG&E Final EIS Part 2 at 5.

[214] SCE Final EIS Part 2 at 11.

[215] PG&E Opening Comments on May 8 Ruling at 4-5, SCE Opening Comments on May 8 Ruling at 3-4, SDG&E Opening Comments on May 8 Ruling at 3-4, Cal Advocates Opening Comments on May 8 Ruling at 3-4.

[216] SBUA Opening Comments on May 8 Ruling at 5-6.

[217] PG&E Opening Comments on May 8 Ruling at 4-5, SCE Opening Comments on May 8 Ruling at 3-4, SDG&E Opening Comments on May 8 Ruling at 3-4, Cal Advocates Opening Comments on May 8 Ruling at 3-4.

VGIC take a progressive integration approach: EDF argues sufficient data exist to incorporate conservative assumptions into the DPEP but simultaneously states that EIS Part 2 demand flexibility assumptions underestimate demand flexibility potential and cost savings; [218] VGIC states demand flexibility should begin informing planning;[219] CalCCA advocates phased integration rather than permanent exclusion, noting that while EIS Part 2 assumptions need refinement, they could provide valuable input once improved through iterative stakeholder process.[220] All three parties reject the premise that assumptions must be fully validated before any planning incorporation.[221]

The IOUs also state that demand flexibility assumptions are immature, do not contemplate feasibility, simultaneously overestimate and underestimate flexibility, or do not include key considerations.[222] SDG&E and PG&E both explicitly state that the flexibility assumptions are not fit for planning incorporation.[223] PG&E focuses on immaturity and lack of cost consideration,[224] while SDG&E focuses on the use of what it says are overly aggressive demand response participation assumptions which SDG&E argues have no programmatic basis.[225] Cal Advocates agrees with PG&E and SDG&E's assessments of the

[218] EDF Opening Comments on May 8 Ruling at 3-4.

[219] VGIC Opening Comments on May 8 Ruling at 4-5.

[220] CalCCAs Opening Comments on May 8 Ruling at 9-10.

[221] EDF Opening Comments on May 8 Ruling at 3-4, VGIC Opening Comments on May 8 Ruling at 4-5, CalCCAs Opening Comments on May 8 Ruling at 9-10.

[222] PG&E Opening Comments on May 8 Ruling at 4-5, SDG&E Opening Comments on May 8 Ruling at 3-4.

[223] PG&E Opening Comments on May 8 Ruling at 4-5, SDG&E Opening Comments on May 8 Ruling at 3-4.

[224] PG&E Opening Comments on May 8 Ruling at 4.

[225] SDG&E Opening Comments on May 8 Ruling at 3.

assumptions and further concurs with their suggestion that IOUs should bolster the verifiability of assumptions by using them to inform pilot programs instead of in planning.[226]

SCE states that the study's demand flexibility assumptions are not reliable and the scenarios assume the existence of distribution flexibility programs that may not be realistically achievable.[227] SCE also states that it is beginning to develop a process to consider demand flexibility estimations into the DPEP but argues that Track 2 is a better venue for solving the particulars of that process.[228] SCE articulates a three-prong readiness framework requiring reliability and cost-effectiveness validation, policy and regulatory framework development, and technical readiness through pilots.[229]

The IOUs state that any forecasted demand flexibility incorporated into distribution planning should flow through the IEPR forecast as load modifiers, not through DPEP inputs.[230] Clean Coalition argues that IEPR load modifiers alone are insufficient to capture the locational and temporal value of DER flexibility and that circuit- and substation-level constraints require a separate locational analysis within the DPEP.[231] UCAN additionally challenges utility representations that IEPR integration could occur by 2027-2028, arguing the timeline is effectively utility-controlled and likely further out than stated.[232]

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[226] Cal Advocates Comments on May 8 Ruling at 6-7.

[227] SCE Opening Comments on May 8 Ruling at 3.

[228] *Ibid*.

[229] *Id. at 2*.

[230] PG&E Opening Comments on May 8 Ruling at 1, SCE Opening Comments on May 8 Ruling at 4, and SDG&E Opening Comments on May 8 Ruling at 6.

[231] Clean Coalition Opening Comments on May 8 Ruling at 5-7

[232] UCAN Opening Comments on May 8 Ruling at 7-10.

While the IOUs state the assumptions should not be integrated, VGIC argues that the overall findings are ready to start informing planning, but that the specific assumptions used lack the granularity necessary to be verifiable.[233] Similarly, EDF contends that some conservative load flexibility assumptions can be used in the yearly DPEP, but that additional integration requires assumption refinement.[234]

CalCCA argues that the reliability of assumptions will be materially affected by current rulemakings and that the Distribution Forecasting Working Group (DFWG) and the Distribution Planning Advisory Group (DPAG) should help refine them.[235]

A central finding across the EIS Part 2 final reports is that demand flexibility can reduce the distribution infrastructure investments required to serve electrification and creates savings for ratepayers. PG&E's Enhanced Demand Flexibility Scenario achieved approximately $1.8 billion in cost reductions relative to its Base (Mitigated) Scenario through 2040; SCE's two demand flexibility scenarios showed reductions between $0.32 to $1.38 billion; and SDG&E's Demand Flexibility Scenario showed reductions of approximately $697 million for the 2025-2040 period.[236] Those results demonstrate that capturing demand flexibility in distribution planning is not a peripheral refinement but a significant affordability lever and intrinsically relevant to the determination of cost-effectiveness of specific DER deployment use-cases.

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[233] VGIC Comments on May 8 Ruling at 4-5.

[234] EDF Comments on May 8 Ruling at 3.

[235] CalCCA’s Comments on May 8 Ruling at 4.

[236] PG&E Final EIS Part 2 at 40, SCE Final EIS Part 2 at 5, SDGE Final EIS2 Part 2 at 1.

The Commission recognizes that the CEC's IEPR forecast is ultimately the appropriate venue to incorporate demand flexibility assumptions into energy demand forecasting at the system level; but the distribution-level implementation will require alignment between the utilities to develop more granular disaggregation practices at the circuit and substation level, informed by their operational data and distinct from the system-level CEC's IEPR forecast. PG&E indicates it is building foundational capabilities for demand flexibility through EPIC 4.08 to make flexibility more planning relevant and directly usable, in particular to improve how flexibility is represented in scenario planning;[237] SDG&E frames "demand response" as a potential load modifier similar to the CEC's Additional Achievable Energy Efficiency framework;[238] and SCE states that demand flexibility assumptions "should not inform forecasting assumptions used in the yearly DPEP until they have been validated with pilots and empirical data" and that "[t]he DPEP should continue to rely on IEPR-informed forecasts and validated methodologies."[239]

8.4. Load Flexibility Scenario within the Scenario Planning Framework.

In December 2025, Resolution E-5414 (Scenario Planning) declined to adopt a stand-alone Demand Flexibility Scenario for the 2025-2026 DPEP cycle, citing the immaturity of demand flexibility methodologies and the pendency of EIS Part 2 final results, while finding it "very important to integrate demand flexibility into scenario planning once the EIS Part 2 Study is completed" and

[237] PG&E Opening Comments on May 8 Ruling at 3-5.

[238] SDG&E Opening Comments on May 8 Ruling at 4 and 6.

[239] SCE Opening Comments on May 8 Ruling at 4.

scoping that determination into Track 1 Phase 2 of this proceeding.[240] With the EIS Part 2 final reports filed in January of 2026, and the comment record developed, the Commission directs the IOUs to propose a Load Flexibility Scenario as the fourth scenario in the annual DPEP Scenario Planning process. The IOUs are directed to use the methodological lessons and directional findings from EIS Part 2 as the analytical foundation and follow the same staged pathway the Commission used to establish the scenario planning framework itself: a workshop that presents the IOUs' proposal, followed by a joint IOU Tier 3 advice letter defining the technical basis, and implementation in the subsequent DPEP cycle.

Specifically, the Commission directs the IOUs to present their proposals for establishing a Load Flexibility Scenario as a fourth scenario in the DPEP scenario planning process at a full-day stakeholder workshop to be held within 90 calendar days of issuance of this Decision. At the workshop, the IOUs shall present the technical elements outlined below. Consistent with the approach ordered in D.24-10-030 for development of the *Scenario Planning Framework,* the workshop will serve as the venue for parties to provide feedback regarding the IOUs' proposal for how to establish a Load Flexibility Scenario as a fourth scenario within the existing DPEP Scenario Planning Framework. The IOUs will also take written comments on the proposal from stakeholders and attach the written comments to the Tier 3 advice letter.

The workshop shall address the following issues:

- Technical methodologies and foundational assumptions of a Load Flexibility Scenario;

[240] Resolution E-5414 at 19-20.

- How the Load Flexibility Scenario relates to and interacts with existing Low, Base, and High scenarios (e.g., whether it is independent from the other scenarios or if it modifies them);
- Integration with each utility's decision logic framework and any required modifications to existing decision logic;
- Proposed criteria for determining implementation readiness.

The Commission also directs the IOUs to file a joint Tier 3 advice letter within 60 calendar days after the workshop providing the technical basis for adopting a Load Flexibility Scenario in the DPEP Scenario Planning process. The Advice Letter must address:

- Each IOU's load-modifier (load flexibility) methodology, including whether inputs are derived from CEC's D-Flex Tool (2023) technical potential outputs, utility-developed disaggregated outputs, a hybrid of the two inputs, or another utility method;
- Locational granularity at which each IOU can resolve demand flexibility inputs (substation, circuit) and the disaggregation method;
- Temporal granularity of modeled flexibility (hourly profiles, peak coincidence with local constraints);
- Applicability and thresholds: the criteria and locations where each IOU proposes to apply the Load Flexibility Scenario, including the determination that system-level levers (e.g., traditional upgrades, IEPR-forecasted load growth assumptions, pending load categories) are sufficient to address distribution grid constraints;
- Proposed definition of the scenario's role, prioritization (similar to the Low Scenario) versus sizing/timing (similar to the High Scenario);
- Guardrails, including reconciliation with the IEPR forecast and prevention of counting multiple times against existing

scenarios, pending loads and other demand side management programs;

- Data infrastructure dependencies (including AMI 2.0 timing) and any temporary solutions pending full deployment of such dependencies; and
- Description of how scenario outputs would be reported in Grid Needs Assessment/Distribution Upgrade Project Report filings.
- How the Load Flexibility Scenario will be incorporated into the existing DPEP Scenario Planning Framework starting in the 2027-2028 DPEP cycle.

The first cycle may function as a proof of concept to validate methodologies and data quality. Subsequent cycles shall inform investment-grade planning decisions consistent with the evolution of forecasting methods, technologies, and customer participation. The advice letter shall address whether and why staged rollout is necessary, in light of each IOU's capabilities and readiness. The advice letters must present a structured pathway for incorporating demand flexibility into distribution planning including advancements in s forecasting methodologies, customer participation, and technologies maturation.

8.5. Distributed Energy Storage

The Commission asked parties to address the limitations of modeling distributed energy storage as a flexible grid asset in the DPEP. PG&E notes that demand flexibility only reduces infrastructure needs by $200 million, which is minimal compared to the full investment horizon, without orchestration capable of respecting feeder, bank, or substation constraints upstream.[241] PG&E also states that distributed energy storage will be incorporated into the model

[241] PG&E Opening Comments on May 8 Ruling at 7.

through EPIC 4.08 – Non-Wires Alternatives (NWA) Integration into Distribution Planning.[242] PG&E states that before integration into the DPEP, more clearly defined performance and enforcement assumptions would ensure that flexible resources can be treated as planning reliable.[243]

SCE states that it is still evaluating how to represent distributed energy storage in the annual DPEP and is unclear whether it should be modeled as a solution side resource or load forecasting input.[244] Before full integration, SCE states that it needs validated performance data at scale while facing uncertainty in customer participation and dispatchability and continued dependence on AMI 2.0 deployment and DER orchestration frameworks.[245] SCE highlights that the DER adoption propensity model also continues to rely on enabling infrastructure that does not yet exist.[246]

SDG&E argues that distributed energy storage needs more program development, specification of DER performance, customer compensation, and demonstration of cost effectiveness, and that distributed energy storage is already modeled in the IEPR system-level forecast.[247]

SBUA supports all the IOUs' stances and recommends a deeper baseline assessment of existing distributed storage resources and an evaluation of current usage and anticipated implementation before any forecasting assumptions are

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242 *Id. at 8.*

243 *Id.* at 8.

244 SCE Opening Comments on May 8 Ruling at 6.

245 *Ibid.*

246 *Ibid.*

247 SDG&E Opening Comments on May 8 Ruling at 7.

made.[248] Clean Coalition emphasizes that distributed energy storage must be considered as part of a larger value stack of grid needs.[249]

VGIC emphasizes the value demonstrated by EV-enabled flexibility in reducing distribution infrastructure needs and recommends that SCE and SDG&E adopt bidirectional EV assumptions consistent with PG&E's approach.[250] SDG&E acknowledges in reply comments the long-term importance of vehicle-to-grid and bidirectional charging but states that current market conditions are too nascent to support reliable planning assumptions, citing limited Commission-approved programs and the absence of measurable participation data at scale.[251]

The Commission agrees with PG&E, SCE, and SDG&E that distributed energy storage may have potential demand flexibility and infrastructure deferral benefits but that significant uncertainty still exists about customer participation in such programs, dispatchability, and interactions with prices signals in rates and tariffs. Accordingly, the Commission does not mandate distributed energy storage as a distribution grid asset in the DPEP at this time, nor do we preclude the IOUs from developing cost effective ways to incorporate distributed storage into DPEP.

9. Summary of Public Comment

Rule 1.18 allows any member of the public to submit written comment in any Commission proceeding using the "Public Comment" tab of the online Docket Card for that proceeding on the Commission's website. Rule 1.18(a)

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248 SBUA Opening Comments on May 8 Ruling at 8

249 Clean Coalition Opening Comments on May 8 Ruling at 6.

250 VGIC Opening Comments on May 8 Ruling at 6.

251 SDG&E Reply Comments on May 8 Ruling at 4-5.

requires that all written public comment submitted prior to the submission of the proceeding are part of the administrative record of the proceeding. Rule 1.18(b) requires that relevant written comment submitted in a proceeding be summarized in the final decision issued in that proceeding.

As of the date of submission of the record, no relevant public comments have been submitted.

10. Procedural Matters

This decision affirms all Track 1 and Track 2 rulings made by the Administrative Law Judge and assigned Commissioner in this proceeding. All Track 1 and Track 2 motions not ruled on are deemed denied. Issues raised by the Motion to Address Unaddressed Issues filed by CBD and UCAN on September 10, 2026 may be considered during the Joint IOU Application proceeding.

11. Comments on Proposed Decision

The proposed decision of Commissioner Darcie L. Houck in this matter was mailed to the parties in accordance with Section 311 of the Pub. Util. Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on __________, and reply comments were filed on _____________ by ________________.

12. Assignment of Proceeding

Darcie L. Houck is the assigned Commissioner, and Jack Chang is the assigned Administrative Law Judge in this proceeding.

Findings of Fact

1. Net ratepayer benefits, operational cost reductions, distribution capacity, reliability, and emissions reduction are primary objectives of DER orchestration and support the efficient and cost-effective integration of DERs into the electric

grid. Customer and aggregation participation pathways may support achievement of these objectives.

2. Thermal overloads, customer energization and interconnection delays, system peak loading, and voltage deviations are primary distribution-system constraints that DER orchestration may help address. DER orchestration may also provide operational benefits, including deferral of distribution-system investments.

3. DER orchestration may provide grid services including reliability, outage mitigation and avoidance, infrastructure deferral, and electrification support. The value and applicability of these services depend on the specific distribution system needs addressed.

4. Adopting the 10 DER orchestration guiding principles listed in the March 23 Ruling, as modified by this decision, together with the addition of "safe and reliable grid operation," will help align the IOUs' Joint DER Orchestration Application with the overall goals of R.21-06-017.

5. The existing Commission-led workshops and subsequent party comments sufficiently developed the record to establish DER orchestration application requirements. Pre-application stakeholder engagement, including through a working group, will provide important input to inform the IOUs' Joint DER Orchestration Application.

6. Topics covered by the pre-application working group led by an IOU-contracted facilitator would include the following:

(a) Guiding principles refinement;

(b) Valuation frameworks;

(c) Cost effectiveness and benefit-cost methodologies;

(d) Interoperability, DSO visibility, and dispatch and control;

(e) Role of DER aggregators;

(f) Flexible dispatching mechanisms;

(g) IOU technical readiness;

(h) Ownership of technology;

(i) Phased implementation and deployment;

(j) DER orchestration and real-time pricing.

7. The value of DER flexibility is highly location dependent, and valuation frameworks for DER orchestration should reflect the specific use case and account for location and timing, where applicable, including location-specific benefits.

8. The record does not support prescribing the ACC or any other single valuation tool for all DER orchestration use cases. The ACC may not fully capture the granular locational and distribution-system value relevant to DER orchestration.

9. DSO-led DER orchestration requires DER visibility into the DSO and DER dispatchability and control as well as coordination with the CAISO during the application process.

10. DER aggregators may provide value by managing customer DERs and providing coordinated DER services, provided that their participation is subject to the same performance and accountability requirements as IOUs.

11. Distribution-level flexible dispatching mechanisms can support DER orchestration by providing a structured means for enabling distribution-level services from DERs. Flexible dispatching mechanisms must be coordinated with DSO operational responsibilities to provide capacity capable of operating during a specific time window at a needed grid location.

12. Participant eligibility, protections against double payment or double counting, performance and measurement and verification requirements, open and nondiscriminatory participation, and appropriate governance and oversight are all relevant considerations for flexibility dispatch mechanisms.

13. The IOUs are at different stages of DER orchestration deployment and readiness and have different existing systems, capabilities, and levels of technical and operational readiness to support DER orchestration.

14. Existing and previously authorized technology investments should be leveraged to the greatest extent possible before IOUs seek authorization for incremental technology investments necessary to support DER orchestration.

15. Broad technology investments are generally more appropriately reviewed through GRCs or other applicable cost-recovery proceedings, where their need, costs, and ratepayer impacts can be evaluated.

16. A phased DER orchestration implementation process would allow each IOU to develop a comprehensive, utility-specific approach to supporting a common DER orchestration framework.

17. A common DER orchestration framework approach will provide efficiencies and better visibility of DER resources that will benefit customers.

18. Dynamic pricing and DER orchestration are complementary but distinct tools. Dynamic pricing assigns value through price signals based on system conditions, while DER orchestration more directly targets specific system needs that vary by location and use case.

19. Customer responses to dynamic pricing may affect load patterns, DER availability, timing, or other factors relevant to DER orchestration, and learnings from dynamic pricing may inform the development of DER orchestration where appropriate.

20. The Commission has already adopted a robust framework for reporting and analyzing equity metrics in distribution planning in Resolution E-5480.

21. Demand Flexibility Scenario assumptions in EIS Part 2 need additional validation before being fully integrated into distribution planning. However, the potential value of the Demand Flexibility Scenarios warrant development of a phased process for incorporating demand flexibility into the DPEP.

22. IOUs-developed methodologies are necessary for incorporating demand flexibility into DPEP at the circuit and substation level.

23. Significant uncertainty exists about customer participation in distributed energy storage programs and their dispatchability.

24. Resolution E-5144 found it "very important to integrate demand flexibility into scenario planning once the EIS Part 2 Study is completed."

Conclusions of Law

1. The IOUs should file a joint comprehensive DER orchestration application within 12 months of this decision's issuance following the overall framework directed in this decision.

2. Net ratepayer benefits, operational cost reductions, reliability, and emissions reduction should be some of the primary objectives of DER orchestration.

3. The IOUs should demonstrate net ratepayer benefits at the use-case level based on measurable benefits and accounting for the full incremental costs necessary to implement and operate each use case.

4. The IOUs should define and justify the grid services that DERs will provide, such as reliability, outage mitigation or avoidance, infrastructure deferral, and electrification support, in their joint application for DER orchestration.

5. The IOUs should link each grid service provided by DERs to specific system and/or distribution needs and justify how those needs were identified. The IOUs should also identify where DER flexibility can provide dependable distribution capacity and whether grid-utilization analysis can be used to identify locations where DER orchestration can effectively address distribution-system needs.

6. Thermal overloads, customer energization and interconnection delays, system peak loading, and voltage deviations, and distribution investment deferrals should be considered in the joint IOU application as primary grid constraints or operational benefits that could be solved or enabled respectively through DER orchestration.

7. The IOU DER orchestration framework application should be guided by the following 11 guiding principles:

- Net-Ratepayer benefits;
- 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; and
- Safe and reliable grid operation.

8. The IOUs shall contract for a facilitator to jointly convene a working group meeting series. The topics covered should include the following:

    a. Guiding principles refinement;

b. Valuation frameworks;
c. Cost effectiveness and benefit-cost methodologies;
d. Interoperability, DSO visibility, and dispatch and control;
e. Role of DER aggregators;
f. Flexible dispatching mechanisms;
g. IOU technical readiness;
h. Ownership of technology;
i. Phased implementation and deployment;
j. DER orchestration and real-time pricing.

9. The working group meeting series, including preparing a report to be included with the Joint IOU DER Orchestration Application, should be completed within 10 months from the issuance of this decision. The IOUs should allow parties to this proceeding to provide informal comments on the draft report within those 10 months. The IOUs should then include the final report as part of the joint application to be filed within 12 months of the issuance of this decision.

10. As part of the working group, or in addition, the IOUs should convene at least one pre-application stakeholder workshop before filing their applications. This meeting or meetings should occur after the issuance of the draft working group report. Additional engagement should occur in consultation with Energy Division and should not delay the application filing deadline.

11. The IOUs should propose and justify in their joint DER orchestration application the valuation methodologies and metrics used to assess proposed DER orchestration use cases. The proposed methodologies should account for the specific use case and, where applicable, its location and timing; differentiate between broader system-level and location-specific distribution-system benefits;

and identify measurable avoided or deferred infrastructure costs and operational benefits.

12. The IOUs may propose the ACC, LNBA, or other valuation tools identified in the record but should explain why their selected tools and methodologies are appropriate for the DER orchestration use cases being evaluated, including whether they provide the necessary level of locational granularity.

13. The Joint IOU Application should include a qualitative discussion of equity benefits that may result from proposed DER orchestration activities, where appropriate.

14. The IOUs should propose cost-effectiveness methodologies that demonstrate a net benefit to ratepayers. Proposed methodologies should evaluate costs and benefits at the use-case level, account for location-specific impacts where applicable, and compare measurable benefits, including applicable avoided costs, against the full incremental costs necessary to implement and operate each use case.

15. The IOUs should propose measurable performance, reliability, and cost-effectiveness criteria for determining when a DER orchestration use case is ready to move from demonstration to broader deployment.

16. The IOUs should identify the performance and reliability criteria DERs must satisfy before their capacity can be relied upon for distribution planning as well as how dependable DER capacity could be represented in distribution planning.

17. The IOUs should explain how demonstrated DER capacity could affect the need, timing, or sizing of traditional distribution investments.

18. The IOUs should specify in their joint application (i) what information should be shared as part of the orchestration plan; (ii) with whom; (iii) with what

required granularity/cadence/latency; and (iv) with what privacy/cybersecurity safeguards.

19. The IOUs should propose in their joint application open, standardized, and interoperable communication protocols that reduce reliance on proprietary OEM clouds and enable grid-edge innovation. Any proposed deviation should include justification for why open, standardized, and interoperable communication protocols will not meet the proposed needs.

20. The IOUs should address in their joint application communication barriers such as excessive access fees, limited functionality, and vendor lock-in that can undermine DER orchestration program cost-effectiveness and ratepayer value.

21. The Joint IOU Application should establish pathways for secure, resilient communication and continuity of grid services, including safeguards in the event of technology provider failures or market exits.

22. The IOUs should identify in their joint application existing systems and capabilities that can support DER orchestration, additional capabilities needed to implement their proposals, and a description of how their proposed architecture reflects their technical and operational readiness.

23. The IOUs should distinguish between existing and previously authorized capabilities from proposed new investments in their joint application.

24. The IOUs should continue TSO-DSO coordination with CAISO during the application proceeding and incorporate relevant developments regarding DER visibility, data exchange, service prioritization, and operational coordination into the application record.

25. IOUs should consider in their joint application the role of DER aggregators in an orchestration framework and allow aggregators to provide coordinated

DER services where their participation adds value, is cost-effective, and does not introduce unnecessary complexity. Participating aggregators should be subject to the same performance and accountability requirements as the IOUs.

26. The IOUs should propose and justify in the joint application flexible dispatching mechanisms that enable DERs to provide distribution-level grid services based on identified system needs. The proposed mechanisms should address participant eligibility, protections against double payment or double counting, and performance, measurement, and verification requirements.

27. The IOUs should describe the operational coordination necessary to enable communication with and dispatchable control over participating DERs to respond to DSO operational needs, identifying implementation differences across the IOUs where necessary.

28. The IOUs should identify in their joint application the roles of utilities, aggregators, CCAs, customers, and other DER providers and address safeguards for competitive neutrality and appropriate Commission oversight.

29. The IOUs should demonstrate in their joint application their respective technological and operational readiness for DER orchestration, which should be assessed based on proven capabilities, including tested pilots and results. Proposed implementation should reflect these differences in operational readiness, so long as the implementation process is working towards a common DER orchestration framework.

30. The IOUs should include in their Joint DER Orchestration Application the specific criteria by which they will demonstrate their individual technological and operational readiness to deploy DER orchestration at scale in a manner that incorporates consistent foundational components that are working toward a common DER orchestration framework.

31. The IOUs should first leverage existing technology investment authorizations or pending technology investment authorizations to implement their DER orchestration frameworks before requesting authorization for incremental technological investments in their joint DER orchestration application.

32. If the IOUs seek authorization for incremental technology investments in the joint DER orchestration application, they should demonstrate why the necessary funding cannot be leveraged from the GRC or other applicable cost-recovery proceedings.

33. The IOUs should be permitted to submit optional Tier 2 advice letters within two months of adoption of this decision to establish memorandum accounts to record administrative costs to support the development of the DER orchestration application, including support for the working group and any minor studies to support the application. Across the three IOUs, the total budget for these memorandum accounts should be capped at $500,000.

34. The IOUs' joint DER orchestration application must specify the source of funding or whether proposed technology investments will be customer- or utility-owned.

35. Dynamic pricing and DER orchestration should be treated as complementary but distinct tools. The Joint IOU DER Orchestration Application should consider dynamic pricing where relevant to the development of DER orchestration, including where customer responses to dynamic pricing may affect load patterns, DER availability, timing, or the cost-effectiveness of proposed DER orchestration use cases.

36. While the EIS Part 2 Equity Scenario findings should not be integrated into the DPEP process, the IOUs must identify candidate locations for DER

investment in disadvantaged and ESJ communities and require project tracking for projects in disadvantaged and ESJ communities..

37. The IOUs should propose a Load Flexibility Scenario as the fourth scenario in the annual DPEP Scenario Planning process.

38. The IOUs should present their proposal for establishing a Load Flexibility Scenario at a full-day stakeholder workshop within 90 calendar days of the issuance of this decision.

39. The IOUs should file a joint Tier 3 advice letter within 60 calendar days after the workshop providing the technical basis for Load Flexibility Scenario inputs and describing how load flexibility scenarios will be incorporated into the scenario planning process of the DPEP.

40. The IOUs should seek informal written feedback on their proposal, which should be included in their advice letter filing.

41. The IOUs should use the methodological lessons and directional findings from EIS Part 2 as the analytical foundation for a Load Flexibility Scenario proposal and follow the same staged pathway the Commission used to establish the scenario planning framework itself: a joint IOU advice letter defining both the technical basis for Load Flexibility Scenario inputs and implementation in the subsequent DPEP cycle.

42. It is reasonable to affirm all Track 1 and Track 2 rulings made by the assigned ALJ or the assigned Commissioner related to the issues considered in this decision.

43. It is reasonable to deny all motions related to Track 1 and Track 2 of this proceeding that were not ruled on.

O R D E R

IT IS ORDERED that:

1. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall submit a Joint Distributed Energy Resources Orchestration Application to the Commission within 12 months of the issuance of this decision.

2. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall host a working group meeting series to address the topic areas this decision directs the utilities to include in a Joint Distributed Energy Resources Orchestration Application. This includes the following:

   a. Guiding principles refinement;
   b. Valuation frameworks;
   c. Cost effectiveness and benefit-cost methodologies;
   d. Interoperability, DSO visibility, and dispatch and control;
   e. Role of DER aggregators;
   f. Flexible dispatching mechanisms;
   g. IOU technical readiness;
   h. Ownership of technology;
   i. Phased implementation and deployment;
   j. DER orchestration and real-time pricing.

3. The working group and draft working group report shall be submitted to parties of this proceeding for informal comment within 10 months of the issuance of this decision. The final working group report, which will consider the comments on the informal report, shall be included as an attachment to the Joint

Investor-Owned Utilities Distributed Energy Resources Orchestration Application.

4. The working group meeting series and joint application shall address and include the primary objectives of distributed energy resources orchestration as set forth in this decision.

5. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are ordered to define and justify in their Joint Distributed Energy Resources (DER) Orchestration Application the proposed grid services that DERs will provide, such as reliability, distribution capacity, outage mitigation or avoidance, infrastructure deferral, and electrification support.

6. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company, collectively the Investor-Owned Utilities (IOUs), are ordered to link each grid service proposed in their Joint Distributed Energy Resources (DER) Orchestration Application to specific system or distribution needs and explain how these needs were identified. The IOUs are ordered to identify where DER flexibility can provide dependable distribution capacity and whether grid-utilization analysis can be used to identify locations where DER orchestration can effectively address distribution-system needs.

7. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are ordered to consider thermal overloads, customer energization and interconnection delays, system peak loading, and voltage deviations as primary grid constraints that may be addressed through distributed energy resources orchestration in their formal application.

8. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are ordered to follow 11 guiding principles as part of their distributed energy resources orchestration applications:

- Net Ratepayer benefits;
- 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; and
- Safe and reliable grid operation.

9. As part of the working group meeting series, or in addition, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company, collectively the Investor-Owned Utilities (IOUs) shall jointly convene at least one pre-application stakeholder workshop during the period between issuance of the draft working group report and the application filing deadline. In consultation with Energy Division, the IOUs may conduct additional joint or utility-specific public engagement as needed. Such engagement shall occur sufficiently early to inform application development without delaying the application filing deadline established by this decision.

10. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are ordered to propose and justify in their Joint Distributed Energy Resources (DER) Orchestration Application valuation methodologies to assess the value of each DER orchestration use case.

The proposed methodologies shall account for the specific use case and its location and timing, where applicable. The proposed methodologies should also distinguish between locational benefits at the system level and circuit level.

11. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are ordered to propose valuation metrics to evaluate the effectiveness of distribution energy resources (DER) orchestration in their Joint DER Orchestration Application.

12. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company may use the Avoided Cost Calculator, Locational Net Benefits Analysis, or other valuation tools in their proposed valuation methodologies but they must explain why the selected tools and methodologies are appropriate for the respective distributed energy resources orchestration use case.

13. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company shall should continue Transmission System Operator-Distribution System Operator coordination with the California Independent System Operator during the Joint Distributed Energy Resources (DER) Orchestration Application proceeding and incorporate relevant developments regarding DER visibility, data exchange, service prioritization, and operational coordination into the application record.

14. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are ordered to include a qualitative discussion of equity benefits in their distributed energy resources orchestration use case valuations where appropriate.

15. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are ordered to propose cost-effectiveness

methodologies for each use case in their Joint Distributed Energy Resources (DER) Orchestration Application that demonstrate net benefit to ratepayers by comparing measurable benefits against the full incremental costs necessary to implement and operate each DER orchestration use case, accounting for location-specific impacts.

16. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are ordered to propose measurable performance, reliability, and cost-effectiveness criteria in their Joint Distribution Energy Resources (DER) Orchestration Application for determining when a DER orchestration use case is ready to move from demonstration to broader deployment.

17. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are ordered to propose in their Joint Distributed Energy Resources (DER) Orchestration Application the performance and reliability criteria DERs must satisfy before their capacity can be relied upon for distribution planning as well as how dependable DER capacity could be represented in distribution planning.

18. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are ordered to explain in their Joint Distributed Energy Resources (DER) Orchestration Application how demonstrated DER capacity could affect the need, timing, or sizing of traditional distribution investments.

19. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are ordered to specify in their Joint Distributed Energy Resources Orchestration Application (i) what information should be shared as part of the orchestration plan; (ii) with whom; (iii) with what

required granularity/cadence/latency; and (iv) with what privacy/cybersecurity safeguards.

20. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are ordered propose in their Joint Distributed Energy Resources Orchestration Application open, standardized, and interoperable communication protocols that reduce reliance on proprietary original equipment manufacturer clouds and enable grid-edge innovation. Any proposed deviation shall include justification for why open, standardized, and interoperable communication protocols will not meet the proposed needs.

21. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are ordered address in their Joint Distributed Energy Resources (DER) Orchestration Application communication barriers such as excessive access fees, limited functionality, and vendor lock-in that can undermine DER program cost-effectiveness and ratepayer value.

22. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are ordered to identify in their Joint Distributed Energy Resources (DER) Orchestration Application each utility's existing systems and capabilities that can support DER orchestration, additional capabilities needed to implement their proposals, and how each utility's proposed architecture reflects their technical and operational readiness to move forward with a consistent DER orchestration framework.

23. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are ordered to distinguish between existing and previously authorized capabilities from proposed new investments in their Joint Distributed Energy Resources Orchestration Application.

24. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are ordered to continue transmission system operator-distribution system operator coordination with the California Independent System Operator during the Distributed Energy Resources (DER) Orchestration Application proceeding and incorporate relevant developments regarding DER visibility, data exchange, service prioritization, and operational coordination into the application record.

25. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are ordered to address in their Joint Distributed Energy Resources (DER) Orchestration Application the potential role of DER aggregators in their proposed orchestration frameworks. If aggregators are included they must add value, not undermine the goal of cost effectiveness, nor add unnecessary complexity.

26. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are ordered to propose in their Joint Distributed Energy Resources (DER) Orchestration Application a flexible dispatching mechanism that enables DERs to offer grid services and addresses participant eligibility, settlement structures, protections against double payment or double counting, and performance, measurement and verification requirements.

27. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are ordered to explain in their Joint Distributed Energy Resources (DER) Orchestration Application how their proposed flexible dispatching mechanisms can schedule and dispatch DER flexibility based on identified distribution system needs and how they will exercise communication and dispatch control over participating DERs, including

the mechanisms necessary to ensure DERs respond to distribution system operator operational needs.

28. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are ordered to explain in their Joint Distributed Energy Resources (DER) Orchestration Application how their proposed flexibility dispatch mechanisms enable open and non-discriminatory participation for utility-, community choice aggregator-, energy services aggregator-, and customer-managed DERs.

29. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are ordered to identify in their Joint Distributed Energy Resources (DER) Orchestration Application the roles of utilities, energy service aggregators, community choice aggregators, customers, and other DER providers and address safeguards for competitive neutrality and appropriate Commission oversight.

30. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are ordered to demonstrate in their Joint Distributed Energy Resources (DER) Orchestration Application their level of readiness for DER orchestration, and that readiness should be assessed based on proven capabilities including tested pilots and results, or based on capabilities recently acquired, soon to be acquired, and that are reasonably expected to be ready to support DER orchestration in the time frame of the application implementation process.

31. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are ordered to include in their Joint Distributed Energy Resources (DER) Orchestration Application specific criteria

by which they will demonstrate their technological and operational readiness to deploy DER orchestration efforts at scale.

32. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are ordered to first leverage existing technology investment authorizations or pending technology investment authorizations to implement the distributed energy resources (DER) orchestration framework before requesting any incremental technological investments in their Joint DER Orchestration Application.

33. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are ordered to demonstrate why funding from their General Rate Case or other cost recovery proceedings cannot be leveraged for any incremental technology investments they seek in their Joint Distributed Energy Resources Orchestration Application.

34. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company, collectively the Investor-Owned Utilities (IOUs), may submit optional Tier 2 advice letters within two months of adoption of this decision to establish memorandum accounts to track incremental costs associated with preparing the Joint Distributed Energy Resources Orchestration Application, including administrative costs, costs to support the working group, and any minor studies needed to support the development of the application. The IOUs must justify any costs recorded in this memorandum account, and the memorandum account shall be capped at a total of $500,000 shared across the IOUs.

35. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are ordered to consider dynamic pricing in their Joint Distributed Energy Resources (DER) Orchestration Application

where relevant to the development of DER orchestration, including where customer responses to dynamic pricing may affect load patterns, DER availability, timing, or the cost-effectiveness of proposed DER orchestration use cases.

36. Within 90 calendar days of the issuance if this decision, Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are ordered to present their proposal of for incorporating a Load Flexibility Scenario into the Scenario Planning process of the Distribution Planning and Execution Process (DPEP) at a full-day stakeholder workshop with presentations addressing the technical elements outlined below.

- Technical methodologies and foundational assumptions of a Load Flexibility Scenario;
- How the Load Flexibility Scenario relates to and interacts with existing Low, Base, and High scenarios (e.g., whether it is independent from the other scenarios or if it modifies them);
- Integration with each utility's decision logic framework and any required modifications to existing decision logic;
- Proposed criteria for determining implementation readiness;

37. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company, collectively the Investor-Owned Utilities (IOUs), are ordered to file a joint Tier 3 advice letter within 60 calendar days after the workshop providing the technical basis for Load Flexibility Scenario inputs. At minimum, the advice letters shall include:

- Each IOU's load-modifier (load flexibility) methodology, including whether inputs are derived from CEC's D-Flex Tool (2023) technical potential outputs, utility-developed disaggregated outputs, a hybrid of the two inputs, or another utility method;

- Locational granularity at which each IOU can resolve demand flexibility inputs (substation, circuit) and the disaggregation method;
- Temporal granularity of modeled flexibility (hourly profiles, peak coincidence with local constraints);
- Applicability and thresholds: the criteria and locations where each IOU proposes to apply the Load Flexibility Scenario, including the determination that system-level levers (e.g., traditional upgrades, IEPR-forecasted load growth assumptions, pending load categories) are sufficient to address distribution grid constraints;
- Proposed definition of the scenario's role, prioritization (similar to the Low Scenario) versus sizing/timing (similar to the High Scenario);
- Guardrails, including reconciliation with the IEPR forecast and prevention of counting multiple times against existing scenarios, pending loads and other demand side management programs;
- Data infrastructure dependencies (including AMI 2.0 timing) and any temporary solutions pending full deployment of such dependencies; and
- Description of how scenario outputs would be reported in Grid Needs Assessment/Distribution Upgrade Project Report filings.
- How the Load Flexibility Scenario will be incorporated into the existing DPEP Scenario Planning Framework starting in the 2027-2028 DPEP cycle.

38. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company are ordered to use the methodological lessons and directional findings from Electrification Impact Study Part 2 as the analytical foundation for a Load Flexibility Scenario.

39. Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company, collectively the Investor-Owned Utilities

(IOUs), are ordered to identify candidate locations for distributed energy resource investment in disadvantaged and environmental and social justice (ESJ) communities based on the findings of the Electrification Impact Study Part 2 Equity Scenario. The IOUs are additionally required to track project progress for all projects in disadvantaged and ESJ communities.

40. All rulings made by the assigned Administrative Law Judge or the assigned Commissioner related to Track 1 and Track 2 of this proceeding are affirmed.

41. All motions related to Track 1 and Track 2 of this proceeding that were not ruled on are denied.

42. Rulemaking 21-06-017 remains open.

This order is effective today.

Dated ____________________________, at San Francisco, California