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PROPOSED DECISION

**Agenda ID #19558
Quasi-Legislative**

Decision _____

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.

R. _____

**ORDER INSTITUTING RULEMAKING TO MODERNIZE THE ELECTRIC GRID
FOR A HIGH DISTRIBUTED ENERGY RESOURCES FUTURE**

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ORDER INSTITUTING RULEMAKING TO MODERNIZE THE ELECTRIC GRID FOR A HIGH DISTRIBUTED ENERGY RESOURCES FUTURE

Summary

The purpose of this Order Instituting Rulemaking is to prepare the electric grid for a high number of distributed energy resources, including those specific to transportation electrification and as defined in Assembly Bill 327 and Public Utilities Code Section 769.^{1,2} This Order Instituting Rulemaking will also address unresolved and ongoing issues from the Distribution Resources Plans proceeding (Rulemaking 14-08-013)³ and Integrated Distributed Energy Resources proceeding (Rulemaking 14-10-003).⁴

1. Background

The California Public Utilities Commission (Commission) opened two proceedings in 2014, the Distribution Resources Plans (DRP) and Integrated Distributed Energy Resources (IDER) proceedings, in response to Assembly Bill

¹ “Distributed resources’ means distributed renewable generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies” (AB 327 and Section 769(a)). The Federal Energy Regulatory Commission (FERC) defines distributed energy resources (DERs) “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 FR 16511, June 1, 2021, at 11).

² All statutory references are to the California Public Utilities Code unless otherwise noted.

³ Among the unresolved issues are whether the Integration Capacity Analysis (ICA) data are sufficient to support DER provider siting needs. Recent stakeholder comments about the ICA data will be carried forward into the new proceeding. For details, refer to the *January 27, 2021, Administrative Law Judge’s Ruling on Joint Parties’ Motion for an Order Requiring Refinements to the Integration Capacity Analysis*.

⁴ To the extent that unresolved issues associated with the Avoided Cost Calculator exist, they are expected to be scoped into a separate proceeding.

(AB) 327 and to fulfill the requirements of Sections 454.5(b)(9)(c), 701.1(a), 769, and 8360(c-i). These two proceedings are expected to close in 2021. Legislative and procedural background summaries are provided below.

1.1. Legislative Background

AB 327 (Perea, 2013) was signed into law by Governor Edmund Gerald Brown on October 7, 2013. AB 327 was a multi-part bill affecting a number of the provisions of regulated utility service and the energy market, including Net Energy Metering, the Renewables Portfolio Standard, natural gas and electricity rates, and electricity resources. Pursuant to AB 327, Section 769 required the Commission to open the DRP proceeding.⁵ Section 769 set forth directives regarding the integration of DERs into investor-owned utility (IOU) electric distribution planning and a mandate for the Commission to review, modify, and approve IOU distribution resources plans.

The IDER proceeding was opened in response to AB 327, specifically, Sections 454.5(b)(9)(c), 701.1(a), and 769, 8360(c-i), to prioritize the procurement of all available cost-effective, reliable, and feasible demand reduction and energy efficiency resources before procuring traditional generation resources.⁶ Subsequently, the IDER proceeding scope expanded pursuant to Decision (D.) 15-09-022 and Sections 769(b)(2) and 769(b)(3) to address tariffs, contracts, or other mechanisms for procuring cost-effective DERs and coordinating with various Commission approved programs, incentives, and tariffs to maximize locational benefits and minimize incremental costs of DERs.

⁵ *OIR Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769*, August 20, 2014, R.14-08-013.

⁶ *OIR to Create a Consistent Regulatory Framework for the Guidance, Planning, and Evaluation of Integrated Demand-Side Resource Programs*, October 8, 2014, R.14-10-003.

1.2. Procedural Background and Summary of Accomplishments

In general, the DRP proceeding focused on distribution planning and the development of tools to facilitate DER integration, and the IDER proceeding focused on DER sourcing mechanisms.⁷ 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.”

The DRP proceeding established three goals: (1) modernize the electric distribution system to accommodate two-way flows of energy and energy services throughout the IOUs’ networks; (2) enable customer choice of new technologies and services that reduce emissions and improve reliability in a cost-efficient manner; and (3) animate opportunities for DERs to realize benefits through the provision of grid services.⁸

The IDER proceeding adopted a Competitive Solicitation Framework that is used by the DRP’s Distribution Investment Deferral Framework (DIDF) to procure DERs to defer traditional investments planned by the IOUs to address grid needs. Four distribution grid services were identified that could be provided by DERs instead of traditional infrastructure: capacity, voltage support, reliability, and resiliency.⁹ As part of the DRP, IOU Distribution Planning

⁷ Both proceedings remain open, however, the Commission intends to conclude them and transfer their records to this OIR. For a full history of the DRP proceeding, *see* R.14-08-013, and for the IDER proceeding, *see* R.14-10-003.

⁸ February 6, 2015, *Assigned Commissioner’s Ruling on Guidance for Public Utilities Code Section 769–Distribution Resource Planning*. R.14-08-013. at 3.

⁹ *Decision Addressing Competitive Solicitation Framework and Utility Regulatory Incentive Pilot*, D.16-12-036, December 15, 2016, at 7 to 8.

Processes (DPPs) were adjusted such that they could be aligned with the new DIDF process.

The DRP proceeding established four key principles: (1) start with a comprehensive, scenario-driven, multi-stakeholder planning process that standardizes methodologies and data requirements to identify locational benefits and costs; (2) move the distribution system towards an open, flexible, and node-friendly network (rather than centralized and linear) that enables seamless DER integration; (3) California's electric distribution system operators (DSOs) should act as a technology-neutral marketplace to coordinate situational awareness and facilitate information exchange while avoiding conflicts of interest; (4) expedite DER participation in wholesale markets and resource adequacy (RA), unbundle distribution grid operations, create a transparent process to monetize DER services, and reduce unnecessary barriers for DER integration.¹⁰

On May 3, 2017, the Commission issued the document, *California's Distributed Energy Resources Action Plan: Aligning Vision and Action* (DER Action Plan). It established vision and action elements that were scoped into the DRP and IDER proceedings.

Since 2014, the DRP and IDER proceedings:

- Made aspects of the electric IOU DPPs transparent through public filings required by the DIDF;¹¹
- Aligned IOU DPP timeframes with the DIDF;

¹⁰ *Ibid.*, at 6 to 8.

¹¹ The IOUs file annual Grid Needs Assessment (GNA) and Distribution Deferral Opportunity Report (DDOR) documents pursuant to D.18-02-004, February 15, 2018, and a series of annual DIDF reform rulemakings for R.14-08-013. The documents provide detailed information about forecast grid needs and investments planned to address the needs. These documents are discussed in utility-hosted Distribution Planning Advisory Group meetings.

- 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 ICA and locational net-benefit analysis (LNBA) tools with sufficient data provided on the DRP Data Portals¹⁴ 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;
- Adopted an ICA methodology that is in use for streamlining Rule 21 interconnection; and
- Ensured IOU General Rate Case (GRC) filings address the technologies and grid upgrades necessary to integrate DERs in accordance with a Grid Modernization Framework.¹⁶

The 2017 DER Action Plan included additional elements that have not been fully resolved and may be included in the scope of the Order Instituting Rulemaking (OIR), such as:

¹² D.16-12-036, December 22, 2016, adopted the Competitive Solicitation Framework for R.14-10-003 that was applied to the DIDF pursuant to D.18-02-004, February 15, 2018, 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.

¹⁴ The DRP Data Portals hosted by the three utilities provide ICA, LNBA, GNA/DDOR, and other data to the public. Confidentiality issues were resolved pursuant to the December 17, 2018 Ruling and July 24, 2018 Ruling for R.14-08-013. (A) The Pacific Gas & Electric (PG&E) portal is available at https://www.pge.com/en_US/for-our-business-partners/distribution-resource-planning/distribution-resource-planning-data-portal.page; (B) San Diego Gas & Electric (SDG&E) at <https://www.sdge.com/more-information/customer-generation/enhanced-integration-capacity-analysis-ica>.; and (C) Southern California Edison (SCE) at <https://ltmdrpep.sce.com/drpep>

¹⁵ D.17-09-026, September 28, 2017, adopted the ICA and LNBA tools for R.14-08-013.

¹⁶ D.18-03-023, March 26, 2018, adopted requirements for IOU Grid Modernization Plans to be included in their GRC filings.

- ICA and LNBA tools and DRP data portal development;
- DER growth forecasting;
- Distribution grid planning, especially with respect to DER hosting capacity;
- DIDF and DER sourcing mechanisms for the deferral of traditional infrastructure (e.g., requests for offers and tariffs);
- Ongoing innovation and demonstration activities;
- Grid modernization framework to accommodate increasing numbers of DERs;
- Advanced smart inverter functionality for dispatch to provide grid services;
- IOU's incorporate into distribution planning the consideration of DER solutions as well as traditional solutions;
- IOU incentives to support DER integration; and
- Utility and affiliate ownership of DERs.

Unresolved and ongoing DRP and IDER proceeding issues are discussed in Section 5.1, below.

2. DER Growth Expectations

In the United States, DERs, including battery storage, customer-sited solar, demand-side management, and electric vehicle (EV) infrastructure are on track to reach 387 GW of cumulative installed capacity by 2025.¹⁷ By comparison, the current combined coal and nuclear power capacity in the United States is substantially less at about 330 GW. Customer-sited solar, residential load-management potential, battery storage, and EV infrastructure is expected to account for more than 90 percent of DER capacity installed through 2025.

¹⁷ Wood Mackenzie defines DERs as having the following characteristics: "grid connected," "customer-sited," MW restricted, and with a "voltage range" (*United States Distributed Energy Resources Outlook: DER Installations and Forecasts 2016-2025E*. Wood Mackenzie, July 2020. Executive Summary, at 1).

Non-residential load management potential is expected to decline through 2025 due to reductions in brick-and-mortar retail, energy efficiency advancement, and fewer commercial and industrial facility developments. While residential DER installations of all types are expected to account for the largest share of DER installations through 2025, non-residential “net” installations of all DER types (including the load management reductions) are forecast to more than double in the same period. The 2020 pandemic is not expected to have a lasting impact on DER investment, although full recovery of DER investment may not occur for several years.^{18,19}

In California, DER growth will continue to increase, especially due to policies and programs driving transportation electrification (TE) and associated DERs (i.e., EVs and EV supply equipment [EVSE]).²⁰ The CEC’s 2020 Integrated Energy Policy Report forecasts extensive increases in behind-the-meter (BTM) solar generation (260 percent), BTM energy storage capacity (770 percent), and EV demand (370 percent) from 2019 to 2030.²¹ Among the factors driving DER

¹⁸ *United States Distributed Energy Resources Outlook: DER Installations and Forecasts 2016-2025E*. Wood Mackenzie, July 2020. Reported in *What the Coming Wave of Distributed Energy Resources Means for the US Grid*. Greentech Media, June 18, 2020. Also from the Wood Mackenzie executive summary for their July 2020 outlook report.

¹⁹ *Annual Energy Outlook 2020*. Table 9. Electricity Generating Capacity. U.S. Energy Information Administration. Accessed online, November 13, 2020.

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

²¹ BTM solar generated 15,800 GWh in 2019 and is forecast to generate 41,200 GWh by 2030 (mid case). BTM energy storage capacity was 340 MW in 2019 and is forecast to reach 2,600 MW by 2030 (mid case). Consumption by all types of EVs is currently about 5,000 GWh and is forecast to reach 18,500 GWh by 2030. See *Final 2020 Integrated Energy Policy Report Update Volume III California Energy Demand Forecast Update*, March 23, 2021, TN #237269.

growth include advancements in technology and cost declines.²² TE infrastructure in the United States is forecast to result in more annual DER capacity additions than solar by 2025.²³ California's TE and climate goals are expected to result in millions of EVs and EVSE DERs by 2030, and Executive Order N-79-20 sets a target for 100 percent of new cars and passenger trucks sold in California are anticipated to be zero emission by 2035. In addition, California policies, programs, and incentives, such as Net Energy Metering and the Self-Generation Incentive Program, continue to drive DER expansion by increasing the financial appeal of DER investment. Legislation aimed at reducing GHG from buildings, Commission proceedings,²⁴ and local reach codes²⁵ are likely to further drive electrification. New energy efficiency savings, however, are expected to decline in California from 24,000 GWh in 2019 to 17,800 GWh in 2030.²⁶

This OIR anticipates a high-penetration DER future and seeks to determine how to optimize the integration of millions of DERs within the distribution grid while ensuring affordable rates.²⁷ DER integration optimization within the

²² Refer to the Wood Mackenzie July 2020 DER outlook report previously cited. The report considers reduced DER installations due to the 2020 pandemic and forecasts the 2019 peak in DER capacity installations will not be exceeded until 2024.

²³ *Ibid.*

²⁴ Senate Bill 1477 and AB 3232 and Building Decarbonization (R.19-01-011) and Long-Term Gas System Planning (R.20-01-007) proceedings.

²⁵ Reach codes are local building codes that seek higher energy savings and emission reductions than those required by the State's Title 24 building standards.

²⁶ *Electricity and Natural Gas Demand Forecast, Statewide and Planning Area Summary*, Cary Garcia, CEC, December 2, 2019, TN #230923.

²⁷ For primary distribution system and/or secondary system (e.g., service line) upgrades to accommodate TE between 2011 and 2018, costs varied widely from \$1 to more than \$338,274 across PG&E, SCE, and SDG&E service areas. The highest average cost (\$19,262) was in PG&E's

Footnote continued on next page.

context of the transmission grid is also relevant to this OIR, and improved coordination between California Independent System Operator (CAISO) and Commission jurisdictions will be considered. In addition, transmission and sub-transmission infrastructure that is Commission jurisdictional will be considered.

This OIR neither seeks to set policy on the overall number of DERs nor does it seek to increase or decrease the desired level of DERs. This OIR focuses on preparing the grid to accommodate what is expected to be a high DER future and capture as much value as possible from DERs as well as mitigate any unintended negative impacts.

3. Rates and Environmental and Social Justice

The Commission held a Rates En Banc²⁸ on February 24, 2021 centered around themes and concepts raised by an Energy Division white paper on California electric and gas cost and rate trends over the next decade.²⁹ En Banc attendees included academics, researchers, utilities, consumer advocates, legislative staff, and other energy stakeholders. The white paper highlights increased rates in recent years that have had a disproportionate negative impact on lower-income customers. Lower-income customers are less likely to invest in

service territory for a distribution upgrade. The highest average service line upgrade cost was \$1,382 (SCE territory). See *Joint IOU Electric Vehicle Load Research*, 7th Report, filed April 2, 2019 at the CEC, at 8. Available at <https://efiling.energy.ca.gov/GetDocument.aspx?tn=228787-14&DocumentContentId=60075>

²⁸ En Bancs are Commission-hosted public events held for a proceeding that are attended by all commissioners instead of the assigned commissioner alone.

²⁹ See *Utility Costs and Affordability of the Grid of the Future: An Evaluation of Electric Costs, Rates, and Equity Issues Pursuant to P.U. Code Section 913.1*, CPUC, February 2021, at <https://www.cpuc.ca.gov/General.aspx?id=6442467418>.

BTM solutions to lower their rates, and impacts are exacerbated by the cost of expensive IOU wildfire mitigation plans.

Two years prior to the Rates En Banc, the Commission adopted an Environmental and Social Justice (ESJ) Action Plan on February 21, 2019. The plan is designed to serve as a roadmap for expanding public inclusion in Commission decision making and improving services to ESJ communities. Among the nine ESJ goals are to, “consistently integrate equity and access considerations throughout Commission proceedings and other efforts.” Rate impacts and alignment with the Commission’s ESJ Action Plan are expected to be considerations in this OIR for some of the scope areas, and we are seeking party feedback on these topics (Section 5.2, Preliminary Scope).

4. Distribution System Operator Roles and Responsibilities

In California, DSO functions, including distribution system planning and operations, are provided by the electric IOUs. As the market evolves into a high-penetration DER scenario, IOU roles will also evolve and there may be a need to consider different DSO roles. The term, “DSO,” is often used in reference 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 integrate DERs at least cost by increasing DER market opportunities and value capture while maintaining system safety and reliability.

The current cost recovery and investment structures for electric distribution systems focuses on large capital investments. A high-penetration DER structure could reduce overall IOU rates of return. For an IOU-administered DSO to be successful, performance incentives not tied to

capital investments may be needed, or there may be a need for a third-party DSO administrator. Potential benefits and costs of various DSO models are identified in the attached 2020 study by DNV GL (Appendix B).³⁰

The DNV GL study also considers the types of coordination and interactions between DSOs and Independent System Operators required under each model. The delineation of DSO roles as opposed to Independent System Operator roles is expected to be relevant to this OIR. For further discussion about the various types of DSO models, see Appendix B.

5. Preliminary Scoping Memo

The Commission will conduct this rulemaking in accordance with Article 6 of the Commission's Rules of Practice and Procedure (Rules). As required by Rule 7.1(d), this OIR includes a preliminary scoping memo as set forth below, and preliminarily determines the category of this proceeding and the need for hearing.

5.1. Issues

Where the prior DRP and IDER proceedings focus on the distribution deferral value of DERs, this proceeding is intended to explore more wide-ranging questions related to distribution planning and modernization of the grid to support high numbers of DER, as further detailed in Section 5.2 below. Given the expansive nature of these questions, the scoping issues proposed in this OIR are more aspirational and less concrete than in prior distribution planning proceedings. We welcome party feedback on the OIR, in

³⁰ The DNV GL study was prepared as Addendum B to DNV GL's February 1, 2020, *Customer Distributed Energy Resources Grid Integration Study: DER Grid Impacts Analysis. In Compliance with Public Utilities Code 913.6. CPUC Legislative Report on Customer Distributed Energy Resources Grid Integration*. Addendum B is circulated as Appendix B to this OIR but was not published with the prior, February 1, 2020, DNV GL report. Page numbering begins at 81 because the study was an addendum to the prior report.

written comments and at the upcoming scoping workshop, towards refining the proceeding scope and schedule such that the Commission may adopt a set of clearly-defined scoping issues and a realistic procedural path to achieving them in the scoping memo for this proceeding that will be issued in accordance with the schedule set forth below. We also note that the adopted scope may evolve over time as our exploration of these questions reveals new or changing avenues of inquiry.

In addition to considering wide-ranging issues related to distribution planning, this proceeding will support DRP and IDER proceeding work streams to continue to implement the requirements of Section 769 with the anticipated closure of these two proceedings. Although much was accomplished in the two proceedings, a great deal of work remains to ensure the grid can efficiently and cost effectively support the growth of DERs. A list of outstanding and new issues is provided in Appendix C. The list was informed by AB 327, Section 769, the DRP and IDER proceeding records, the Commission's 2017 DER Action Plan, and, in part, by discussions during an informal 2020 DRP "Retrospective" meeting with a range of stakeholders to discuss the DRP (Appendix D). This OIR, however, may not address the full list of issues identified in appendices C and D or may address different or modified issues. The preliminary scope is provided in the following section including a list of questions to help refine the scope.

5.2. Preliminary Scope

With respect to grid modernization, this OIR will consider increasing community engagement with distribution planning and investigating IOU, distribution operator, and DER stakeholder roles and responsibilities that:

- Enable swift evolution of grid capabilities and operations to integrate solar, storage, EVs/EVSE and other DERs to meet the State’s 100 percent clean energy goals;
- Improve distribution planning, including charging infrastructure forecasting to support cost effective and widespread TE; and
- Optimize grid infrastructure investments by facilitating community input about planned developments, DER siting plans, and resiliency needs.

A series of scoping questions are posed to all interested parties to facilitate feedback on these broad intentions. The questions are organized under three tracks (topic areas).

Track 1 broadly focuses on high-level policy issues involving distribution system operator roles and responsibilities as well as IOU and aggregator business models. This track is expected to address long-term policy issues and could result in findings that implicate potential action beyond the timeframe of this OIR. Topics addressed in this track are based, in part, on the attached 2020 study by DNV GL about DSO models (Appendix B). The DSO study discusses new approaches to distribution system planning, operations, and ratemaking that may improve DER integration efficiency and cost effectiveness. A central Track 1 activity will be the completion of a consultant technical report that provides an in-depth review of DSO models, distribution operator roles and responsibilities, and implementation feasibility. Stakeholder engagement will provide input on the study’s scope and objectives, draft deliverables, public engagement, and findings. Activities in Track 1 are expected to include an En Banc to present study findings and gather feedback from national and international experts on electric grid models and architectures (both existing and conceptual) and the state-of-the-art on approaches to DER integration.

Depending on the scope of the study and stakeholder comments, some findings might be rolled into a successor proceeding.

The second track focuses on near-term evolution and improvement of the adopted DRP frameworks, analytic tools, and planning processes³¹ into a more holistic DPP. Track 2 includes carryover work from the previous DRP and IDER proceedings as well as a reformed focus on optimizing grid investments to accommodate DER growth while supporting resiliency and electrification goals and facilitating community engagement. Track 2 activities would be staff led, including a staff proposal and public workshops regarding DIDF and DPP improvement. Coordination with the TE proceeding Rulemaking (R.)18-12-006 will be important during Track 2, especially regarding the development of approaches to identifying grid locations with available capacity to support EV charging and incorporating cost-effective strategies into the DPP to mitigate charging loads and enable EVs to provide grid services.^{32,33}

The third track focuses on grid modernization investments in the near term and medium term, operationalizing smart inverters to leverage advanced functionality to provide grid services, and furthering the alignment of GRC filings with the planned infrastructure investments identified during IOU distribution planning. Alignment of quadrennial GRC costs requests with annual

³¹ The tools and planning processes include ICA, LNBA, DER Growth Forecast Working Group, and the DIDF (GNA/DDOR and Distribution Planning Advisory Group).

³² Senate Bill 676 (2019) and Section 740.16 require, among other things, that the Commission to consider how, or if, electric vehicle grid integration can mitigate any generation, transmission, or distribution costs (proceeding R.18-12-006).

³³ Assembly Bill 841 (2020) and Section 740.19 require that the Commission change the practice of authorizing utility-side distribution infrastructure needed to charge electric vehicles on a case-by-case basis to a practice of considering that infrastructure as a core utility business, treated the same as other infrastructure authorized in GRCs (proceeding R.18-12-006).

GNA/DDOR filing costs estimates continues to be challenging.³⁴ The Track 3 grid modernization and smart inverter topics are expected to be addressed in a working group format facilitated by a third-party consultant that culminates in a report with findings and recommendations. A staff proposal and workshop would follow the working group report. The GRC alignment topic may be addressed separately through staff led work and workshops.

General Questions Relevant to All Tracks

1. How could this proceeding advance or challenge achievement of the nine ESJ Action Plan goals?³⁵
2. How should the term DER be defined as the Commission plans for the future grid? Consider capacity (megawatts), energy (megawatt hours), BTM, and in front of the meter in responses as well as the existing DER definition provided in AB 327 and Section 769(a) and any other relevant legislative or regulatory code DER definitions, including those from sources outside of California.

Track 1: Distribution System Operator Roles and Responsibilities

1. Should the Commission investigate how to redefine electric distribution IOU roles and responsibilities to accommodate a high-DER future grid, appropriately limit market power, and ensure open

³⁴ See reforms 18 and 34 in the *May 11, 2020 Administrative Law Judge's Ruling Modifying the Distribution Investment Deferral Framework Process*. Reform 18 requires that project IDs be used in the DDOR to enable project information (e.g., cost) to be tracked in GRC filings. Reform 34 requires the IOUs to explain discrepancies between project costs reported in the DDOR and in GRC filings.

³⁵ Refer to the Commission's *ESJ Action Plan*, Version 1.0, February 21, 2019 at <https://www.cpuc.ca.gov/esjactionplan>.

access for DER providers and aggregators offering retail and wholesale grid services?^{36,37} If so, how?

2. In what ways would a DSO and the various DSO models increase or decrease ratepayer costs and enhance or impede equity?
3. Should the grid architecture discipline³⁸ be used to establish an overarching grid vision and design that optimizes distribution investments to accommodate high numbers of DERs? If yes, how and over what timeframe?
4. Should the IOUs be incentivized to cost-effectively prepare for widespread DER deployments? If so, how?³⁹
5. What policies could the Commission adopt quickly to enable aggregators to increase the scope of services they provide the distribution grid?

Track 2: Distribution Planning, Data Portals, Community Engagement, and DER Integration

³⁶ On September 17, 2020, the FERC issued the landmark Order 2222, enabling DER aggregators to compete in wholesale electric markets. In the Order, FERC suggested that the CAISO Distributed Energy Resource Provider (DERP) tariff could provide an example of how retail authorities could be involved in coordinating the participation of DER aggregations.

³⁷ DSO models, the CAISO DERP tariff, and CAISO Distributed Energy Resource Aggregations are further discussed in, *Coordination of Transmission and Distribution Operations in a High Distributed Energy Resource Electric Grid*, June 2017, by staff at the CAISO, PG&E, SCE, SDG&E, and More than Smart. Available at:

https://gridworks.org/wp-content/uploads/2018/11/MoreThanSmartReport-CoordinatingTransmission_DistributionGridOperations.pdf

³⁸ Grid Architecture is a discipline with roots in system architecture, network theory, control engineering, and software architecture applied to the electric power grid. An architectural description is a structural representation of a system that helps people think about the overall shape of the system, its attributes, and how the parts interact. Most of all, grid architecture provides insight to stakeholders for making informed decisions about grid modernization when planning for the future electric system. See <https://www.pnnl.gov/grid-architecture>.

³⁹ The Hawaii Public Utilities Commission adopted a performance-based ratemaking framework that is designed to incentivize the utility to prepare for DER deployment? on December 23, 2020, see https://puc.hawaii.gov/wp-content/uploads/2020/12/PBR-Phase-2-DO.Page-Press-Release.Final_.12-22-2020.pdf.

1. To what extent should this proceeding further examine the utility DPP, moving beyond the current DIDF focus?
 - a. Should the Commission evolve the DIDF into a broader DPP that captures additional value from DER services beyond distribution deferral and focuses more broadly on DER siting optimization?
 - b. In what ways could the IOU DPPs improve to usher DERs to areas where excess grid capacity is forecast to exist rather than reacting to unstructured DER deployments? How should this be accomplished and in what incremental steps?
2. Should IOU distribution planning consultation processes for local agencies and stakeholders be expanded and formalized in a DPP guidelines document that requires IOUs to increase collaboration including the presentation of distribution upgrade plans to a wider audience to help ensure community energy needs and planned developments are fully integrated into IOU planning?⁴⁰
 - c. How frequent should the consultations be and at what level of local government (*e.g.*, city or county level)? What should be the scope of outreach, including the scope of outreach to tribal governments?
 - d. Should DPP outreach be coordinated and/or combined with associated community engagement activities (*e.g.*, those required by the wildfire mitigation, de-energization, microgrids and resiliency, climate adaptation, and/or other proceedings)?⁴¹
 - e. Should DPP outreach play a role in supporting development of community-scale DERs (*i.e.*, DERs smaller than utility scale but significantly larger than typical single-customer residential DERs) or

⁴⁰ In 2020, Oregon (Order 20-485, Docket No. UM 2005) established community and stakeholder engagement processes and required increased data transparency for distribution planning, and Colorado opened a proceeding to develop similar rules for Distribution System Planning (Decision C20-0837, Proceeding 20R-0516E).

⁴¹ D.20-03-004, March 18, 2020, required community outreach before, during, and after wildfires (wildfire mitigation, R.18-10-007). D.20-05-051, June 5, 2020, required that the IOUs convene quarterly (at minimum) working groups at a regional level and establish advisory boards (de-energization, R.18-12-005). D.20-06-017, June 17, 2020, required that the IOUs conduct face-to-face, county-level community outreach on a semi-annual basis (microgrids and resiliency, R.19-09-009). D.20-08-046, September 3, 2020, requires that the IOUs develop Community Engagement Plans for disadvantaged communities (climate adaptation, R.18-04-019).

virtual power plants⁴² that provide community benefits like equity and resiliency⁴³? If so, what should that role be?

3. General Order (GO) 131-D establishes when IOUs are required to seek Commission permits to construct electrical facilities with a formal application process. Consistent with State law, when a Commission permit is required, the Commission usually serves as the Lead Agency for California Environmental Quality Act (CEQA) compliance. Additionally, GO 131-D establishes policy and requirements governing infrastructure projects when formal Commission permits are not required. In what ways should utility DPPs be updated and reflected in GO 131-D (e.g., at Section III.C. and Section XIV) to ensure adequate community outreach and local agency consultation occurs to meet Commission policy objectives, even when the particular electric infrastructure does not require a formal Commission permit?⁴⁴
 - f. Should GO 131-D and/or the DIDF be updated to clarify how electric grid projects that require a Commission permit interact with the DIDF process, and if so, how? Such projects may be identified via DIDF when they are in a Pre-Application phase (before filing for a permit and commencing CEQA review) and/or Post-Application

⁴² Policies related to DERs organized as microgrids pursuant to the Code Section 8370 definition are scoped into proceeding R.19-09-009. Microgrid and resiliency issues will be addressed in proceeding R.19-09-009. To the extent the proceeding opened pursuant to this OIR addresses distribution planning and grid modernization issues that impact microgrids and resiliency issues, the proceeding will coordinate closely with proceeding R.19-09-009.

⁴³ Commercial/industrial rooftop or community-scale solar installations could be cost-effective for powering EVSE as opposed to installing new distribution infrastructure (*Distribution Costs and Distributed Generation*, February 8, 2021, at [https://energyathaas.wordpress.com/2021/02/08/distribution-costs-and-distributed-generation.](https://energyathaas.wordpress.com/2021/02/08/distribution-costs-and-distributed-generation/))

⁴⁴ GO 131-D, Section III.C., states that electric distribution (under 50 kV) facilities neither require a Commission permit nor discretionary permits or approvals by local governments. "However, to ensure safety and compliance with local building standards, the utility must first communicate with, and obtain the input of, local authorities regarding land use matters and obtain any non-discretionary local permits required for the construction and operation of these projects." Section XIV.B. further states, "in locating such projects, the public utilities shall consult with local agencies regarding land use matters."

phase (when there is already a filing at the Commission in active review).⁴⁵

4. How should the DPP/DIDF processes improve to support widespread TE?
 - g. What improvements to GNA load forecasting can be made to identify grid investments needed to support TE goals? Consider different types of charging sites in the response, e.g., charging stations with high loads (e.g., transit depots or Direct Current [DC] Fast Charging plazas)⁴⁶ as opposed to high numbers of dispersed level 1 and level 2 EVSE?⁴⁷
 - h. What coordination is needed between the Commission, CEC, and CAISO to improve the use of EV forecast data for distribution planning purposes?⁴⁸
 - i. How should DPP/DIDF processes be coordinated with other Commission processes/policies/proceedings to adequately and efficiently plan for distribution grid upgrades triggered by TE and to reduce/defer/avoid grid upgrades where feasible?⁴⁹

⁴⁵ “Pre-Application Projects” are transmission and sub-transmission projects with associated grid needs under Commission jurisdiction that are expected to require review pursuant to GO 131-D. Applications for projects filed under GO 131-D typically require review pursuant to the California Environmental Quality Act as well. Projects included in IOU DIDF filings that are already undergoing review pursuant to a GO 131-D application process are considered “Post-Application Projects.”

⁴⁶ According to PG&E, high-speed EV charging facilities may result in customer load applications for 5 MW to 10 MW at a specific location (PG&E 2020 DDOR at 27).

⁴⁷ AB 2127 (Ting, 2018) and Section 25229 requires the Commission to support the CEC with their biannual electric vehicle infrastructure projections that considers all necessary charging infrastructure to accelerate the adoption of electric vehicles to meet State goals.

⁴⁸ CEC’s EVSE Deployment and Grid Evaluation model (the “EDGE” model) is used to geospatially analyze and track local grid capacity, air quality, travel demand, and equity considerations. It uses the ICA and GNA data to identify areas where grid capacity is available for EVSE (e.g., chargers). For further information, refer to the CEC’s *Assembly Bill 2127 Electric Vehicle Charging Infrastructure Assessment*, January 7, 2021.

⁴⁹ The December 21, 2020, *Decision Concerning Implementation of Senate Bill 676 and Vehicle-to-Grid Integration Strategies*, (D.20-12-029 for proceeding R.18-12-006), states at 31, “The large electrical corporations should consider opportunities to advance distribution deferral in any pilots or other policy actions under this decision, as well as other venues related to distribution

Footnote continued on next page.

- j. When will EVs, EVSE, and related technologies (e.g., automatic load management systems) be available to reduce/defer/avoid distribution system upgrades and provide other grid services? At what scope, under what circumstances, and what are some current examples? What are the top five barriers to being available.⁵⁰ What associated policy changes and/or technology development are necessary and why?
5. What additional types of planned investments should be considered for deferral (e.g., DERs installed instead of replacing aging infrastructure or DERs installed such that loads can be lowered to extend the life of existing infrastructure)?
6. Should IOUs incorporate the use of DERs as opposed to traditional infrastructure into their standard practice of planning for distribution investments? If so, how should this be achieved?
7. How should ICA data and calculations be improved to enhance accuracy and usefulness for DER planning and interconnection (especially with respect to TE)?⁵¹
- k. Should ICA data be aligned with annual GNA load forecast results? If so, how and with what objective?

infrastructure planning (such as distribution resources plans). In addition, integrating VGI [Vehicle-Grid Integration] across all relevant business activities (see section 6.6) is particularly relevant for avoiding distribution upgrades as noted in the draft TEF [Transportation Electrification Framework] (at 23) including any future solicitations for distribution deferral projects.” The IOU vehicle-grid integration load profiles coming in March 2022 (D.20-12-029 at 58 and 78) may inform DIDF deferral opportunity selection and DER-provider offers in response to solicitations.

⁵⁰ The Vehicle-Grid Integration Working Group identified avoiding utility system upgrades as an application of vehicle-grid integration. Managing charging to leverage time-of-use rates and reduce customer bills is another example. Refer to the June 30, 2020, *Final Report of the California Joint Agencies Vehicle-Grid Integration Working Group*, at: https://gridworks.org/wp-content/uploads/2020/09/GW_VehicleGrid-Integration-Working-Group.pdf.

⁵¹ The *January 27, 2021, Administrative Law Judge’s Ruling on Joint Parties’ Motion for an Order Requiring Refinements to the Integration Capacity Analysis*, orders the IOUs to retain an independent technical expert to review their data validation plans and efforts.

- l. To what extent are the ICA data currently available on the DRP Data Portals useful for TE planning purposes? What improvements are necessary to increase the utility of this data?⁵²
 - m. How should the IOUs' DRP Data Portals (including the ICA tool) be improved and better coordinated with other proceedings?⁵³ For example, transmission infrastructure, grid investment, Public Safety Power Shutoff, and weather data hosted by the pending IOU Microgrid Data Portals may be useful for DER planning conducted using the DRP Data Portals. In addition, it may not be clear which data to be hosted on the Microgrid Data Portals should be considered confidential (or access limited)⁵⁴ pursuant to DRP proceeding decisions on confidentiality.
8. What carryover issues from DRP and/or IDER (not already addressed in the scoping questions) should be continued in this OIR?
- n. Should additional DER tariff pilots be implemented to extract more value from BTM DERs and further scale the DIDF program (e.g., a regional pilot⁵⁵)? Consider the evaluation of ongoing pilots in response to this question.

⁵² See Section 3.1.4 in the *Transportation Electrification Framework, Energy Division Staff Proposal*, February 2020, regarding DRP proceeding coordination and ICA data use. Available at: <https://www.cpuc.ca.gov/zev>.

⁵³ The IOUs are developing Microgrid Data Portals for the microgrids and resiliency proceeding (R.19-09-009). SCE currently expects their Microgrid Data Portal to be fully deployed in 2022. PG&E expects to fully deploy in 2021, states SCE, and SCE's portal might be partially deployed late 2021. SCE indicated that the infrastructure behind SCE's DRP Data Portal is out of capacity to accommodate microgrid data (see SCE Reply to Protest of Kern and Santa Barbara Counties of Advice 4294-E, October 14, 2020). SCE's new Microgrids for Developers webpage is intended to be a guide for local and tribal government entities interested in deploying microgrids (see Supplement to Advice Letter 4259-E, Southern California Edison Company's Resiliency Project Engagement Guide, November 17, 2020).

⁵⁴ D.20-06-017, Ordering Paragraph 11(b) at 127, states that local and tribal government access to Microgrid Data Portal data should not require the execution of non-disclosure agreements but the data should still be subject to confidential treatment.

⁵⁵ Refer to CECI Pilot 2 and CESI Pilot 3 (planning area pilots) in the Staff Proposal, *Distributed Energy Resources Deferral Tariff and Request for Offer Streamlining*, October 5, 2020, proceeding R.14-03-003. It is an attachment to both the proposed and adopted decisions (D.21-02-006).

- o. In what ways should multiple-use application rules be updated to maximize the value of providing both RA and distribution deferral services?⁵⁶

Track 3: Smart Inverter Operationalization, Grid Modernization, and GRCs

1. Should the framework for grid modernization adopted in D.18-03-023, including Grid Modernization Plans, be revisited and updated, and if so, what updates are needed?
2. Should TE needs be updated in the IOU Grid Modernization Plans? If so, how, and in what ways should the Grid Modernization Plans be coordinated with IOU TE plan filings?⁵⁷
3. The aforementioned framework for grid modernization provides guidance for how grid modernization requests should be presented in GRCs. It stops short of recommending which technologies to adopt. Should the framework develop specific investment priorities and functional needs for grid modernization?⁵⁸
4. How should the development and enactment of smart inverter operationalization capabilities (i.e., advanced functions) as defined in D.20-09-035⁵⁹ and Working Group Four⁶⁰ be accomplished such that

⁵⁶ The California Energy Storage Alliance commented that multiple-use application Rule 6 should allow the same capacity to be used at the same time for both RA and distribution deferral purposes and that RA value should be available to deferral providers in all days of a month when not otherwise counted toward an IOU's RA capacity (Opening Comments, Modifying the Distribution Investment Deferral Framework, January 20, 2021, R.14-08-013, at 7 to 9). SCE replied that they are open to increased rule flexibility while ensuring reliability. They note that RA program rules would need to be revised such that capacity could be provided for timeframes of less than an entire month (SCE Reply Comments, March 12, 2021, at 11 to 12).

⁵⁷ See Section 3.1 in the *Transportation Electrification Framework, Energy Division Staff Proposal*, February 2020, regarding the Staff proposal for IOU strategic, long-term Transportation Electrification Plans. Available at <https://www.cpuc.ca.gov/zev>.

⁵⁸ PG&E's next GRC filing date will be in June 2021, SDG&E's in May 2022, and SCE's in May 2023. See Appendix B to D.20-01-002 for the GRC safety, reliability, and revisions proceeding (R.13-11-006), which implement four-year GRC cycles instead of three-year cycles.

⁵⁹ Decision Adopting Recommendations from Working Groups Two, Three, and Subgroup, D.20-09-035, September 30, 2020, R.17-07-007.

⁶⁰ Rule 21 Working Group Four Final Report, August 12, 2020, California Public Utilities Commission Interconnection Rulemaking (R.17-07-007). Available at <https://gridworks.org/wp-content/uploads/2020/08/R21-WG4-Final-Report.pdf>.

DERs, utilities, and aggregators fully leverage smart inverter advanced functionality to provide grid services that are safe and improve reliability and resiliency?

5. How can the planned investments identified in the annual DDOR be further aligned with investments proposed and approved in the quadrennial GRCs to reduce ratepayer costs and provide maximum value to ratepayers?

5.3. Anticipated Technical Support Needs

The April 13, 2020, *ALJ's Ruling Modifying the Distribution Investment Deferral Framework Process* for proceeding R.14-08-013 authorized the use of reimbursable funds for Energy Division to hire consultants to support the DRP proceeding. Up to \$4,000,000 over four years was authorized, but the funds were not spent and would be applied to a consultant support contract primarily for this proceeding.

Consultants would be expected to support DPP/DIDF improvement activities, annual implementation, and TE and other cross-proceeding coordination; evaluate and test complex DPP/DIDF process standardization and reform concepts; support community outreach efforts; make technical recommendations for updating and improving various IOU data portals⁶¹ and track resultant portal improvements; provide GRC technical support including grid modernization plan development and review; provide TE-specific technical support; consider complex resiliency planning and infrastructure siting issues; and investigate and develop the means for optimizing the siting, sizing,

⁶¹ The DRP Data Portals hosted by the three IOUs provide ICA, LNBA, GNA/DDOR, and other data to the public to support, among other goals, the siting and sizing of customer-owned DERs, public vetting of the IOU's GNA/DDOR filings, and third-party bidding on distribution deferral opportunities. Data specific to microgrid and resiliency planning are under development by the IOUs. Other electric and gas IOU data portals that may be developed would also be incorporated into the consultant's scope of work.

interconnection, and dispatch of DERs, which may include accessing and analyzing large datasets from the utilities and other sources and facilitating the development of IOU capabilities to dispatch DERs to provide grid services. Consultants also would conduct an in-depth study and facilitate workshops on distribution operator roles and responsibilities, DSO models, grid architecture, and associated topics as described in the preliminary scope section of this OIR. The analysis and development of DER sourcing mechanisms and general technical support related to DER and TE planning and other aspects of this proceedings scope (Tracks 1, 2, and 3) would also be supported by consultants.

5.4. Coordination with California Energy Commission Data Gathering and Analytics Activities

The work contemplated in this OIR aligns with analytics activities underway at the CEC to increase understanding about plausible levels of DER deployment and their grid implications, the value and scope of services DER can provide to address reliability and Senate Bill 100 goals,⁶² and anticipated levels of transportation electrification and its grid implications. Collaboration with the CEC throughout the course of the proceeding is anticipated to support decision making in each track as appropriate based on the contents of CEC independent research and development efforts. In coordination with Commission staff, CEC reports may be circulated to the proceeding service list, and CEC staff may present at proceeding workshops.

⁶² The technical analysis used to produce the *2021 SB 100 Joint Agency Report: Achieving 100 Percent Clean Electricity in California, An Initial Assessment* (March 2021) focused on large-scale generation and the transmission grid. It did not focus on how DERs could help reach Senate Bill 100 goals (100 percent renewable and zero-carbon retail electricity by 2045). The report is available at: <https://www.energy.ca.gov/sb100>. CEC staff plan to analyze the potential for DER to offset anticipated increases in electrification loads due to decarbonization in future years.

In addition, the CEC is in the process of assembling a large amount of data to analyze the impacts of DER on reliability. The CEC has developed the capability to retrieve, organize, store, and govern access to the data and is positioned to act as a central repository for energy data and provide access to Commission staff and others.⁶³ The CEC and Commission are collaborating on gathering and organizing data into the central repository. Assembling the data in one place will facilitate the use of big-data analytical techniques that could produce information that benefits Track 2 (DPP) decision making and, potentially, decision making for the other two tracks.

6. Categorization; *Ex Parte* Communications; Need for Hearing

Rule 7.1(d) provides that an OIR shall preliminarily determine the category and need for hearing. This rulemaking is preliminarily determined to be quasi-legislative as defined in Rule 1.3(e). Accordingly, *ex parte* communications are permitted without restriction or reporting requirement pursuant to Article 8 of the Rules.

It appears that the issues may be resolved through comments and workshops without the need for evidentiary hearings. Any person who objects to the preliminary hearing determination shall state the objections in their comments on this OIR. The assigned Commissioner will make a final

⁶³ The CEC is currently gathering the following datasets (among others): Advanced Metering Infrastructure data in hourly (8760) or 15-minute intervals (kW, kWh) with Greenwich Mean Time timestamps; power flow modeling data; utility wildfire datasets; IOU hosting capacity information for each line segment, feeder, and substation; existing solar installation data from California Solar Initiative and Net Energy Metering interconnection datasets; existing Self-Generation Incentive Program projects data; existing demand response projects data; and DIDF filings data.

determination on the need for hearing in the Scoping Memo and Ruling issued following a prehearing conference (PHC).

7. Preliminary Schedule

The preliminary schedule for this proceeding is set forth below and includes the provisions for the filing of comments on the OIR. The assigned Commissioner or ALJ may change the schedule and scope as necessary to provide full and fair development of the record. Potential workshops, working groups, consultant reports, staff proposals, and decisions are identified in the table below.

Item	Date
Comments on the OIR filed and served	45 days after OIR adoption
Prehearing Conference	August 2021
Energy Division Workshop on proceeding scope and organization	September 2021
Reply comments on the OIR filed and served	15 days after workshop
Scoping Memo and Ruling	2021 (Quarter 4)
Track 1: Distribution System Operator Roles and Responsibilities	
DSO roles and responsibilities White Paper and Workshop on scope of technical report	2022 (Quarter 1)
Draft documents and additional workshops may be required depending on scoping results.	TBD
Technical Report on DSO roles and responsibilities, DSO models, grid architecture, implementation feasibility, etc. and En Banc .	2024 (Quarter 3)
Proposed Decision on DSO roles and responsibilities	2024 (Quarter 4)
Track 2: Distribution Planning, Data Portals, Community Engagement, and DER Integration	

DIDF Guidelines ⁶⁴ document circulated for comment	2022 (Quarter 2)
Phase 1 electrification impacts on distribution planning Technical Report ⁶⁵ and workshop	2022 (Quarter 3)
Energy Division Workshop on DPP improvement	2022 (Quarter 4)
Phase 2 electrification impacts on distribution planning Technical Report ⁶⁶ and workshop	2023 (Quarter 1)
DRP Data Portals Improvement Technical Report and Workshop	2023 (Quarter 4)
Staff Proposal for DPP Guidelines ⁶⁷ document and workshop	2024 (Quarter 1)
Proposed Decision on DPP Guidelines	2024 (Quarter 2)
Track 3: Smart Inverter Operationalization, Grid Modernization, and GRC Alignment	
Smart inverter operationalization Working Group convenes for one year	2022 (Quarter 1)
<ul style="list-style-type: none"> • Smart inverter operationalization Working Group Report • Staff Proposal and Workshop on smart inverter operationalization 	2023 (Quarter 2)
Staff Proposal and Workshop on grid modernization improvement and GRC alignment	2023 (Quarter 3)

⁶⁴ The DIDF Guidelines would document all existing DIDF rules and requirements pursuant to decisions and rulings of the DRP and IDER proceedings and associated proceedings as relevant.

⁶⁵ The Phase 1 Electrification Impacts on Distribution Planning Report would forecast the scope and cost of grid impacts.

⁶⁶ The Phase 2 Electrification Impacts on Distribution Planning Report would be prepared as a Staff Proposal focused on improving distribution planning to mitigate grid impacts identified in the Phase 1 report.

⁶⁷ DPP Staff Proposal would include details from the DIDF Guidelines and electrification impacts, DRP Data Portals improvement, grid modernization, and smart inverter operationalization reports and proposals. The DIDF Guidelines would be replaced by a new, DPP Guidelines document.

Proposed Decision on smart inverter operationalization, grid modernization improvement, and GRCs	2023 (Quarter 4)
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A listing of expected technical reports and staff proposals identified in the schedule is provided here:

1. White paper on international and national grid models, DER integration approaches, grid architecture, DSO concepts, and planning for California's future grid
2. DIDF Guidelines (to document existing DIDF requirements)
3. Phase 1 and 2 Electrification Impacts on Distribution Planning reports
4. DRP Data Portal Improvement Technical Report
5. Staff Proposal for DPP Guidelines (will supersede DIDF Guidelines)
6. Smart Inverter Operationalization Working Group Report
7. Smart Inverter Operationalization Staff Proposal
8. Grid Modernization Plan Improvement and GRC Alignment Staff Proposal
9. Technical Report on Distribution Operator Roles and Responsibilities

Most of the technical reports and staff proposals are anticipated to include a workshop. The workshop purpose may be to receive input on report/proposal scope or to present findings. Party comments would be solicited on all reports and staff proposals.

This proceeding will conform to the statutory case management deadline for quasi-legislative matters set forth in Section 1701.5. In particular, it is our intention to resolve all relevant issues within 36 months from the date that the scoping memo for this proceeding circulates. In using the authority granted in Section 1701.5(b) to set a time longer than 18 months, we consider the number and complexity of the tasks, including sufficient time to develop white papers

and staff proposals on technically complex matters, and the need to coordinate with multiple other proceedings and working groups.

This schedule will be set forth in the scoping memo and may be revised by the assigned Commissioner or the assigned ALJ to promote efficient and fair administration of this proceeding.

8. Invitation to Comment on Preliminary Scoping Memo and Schedule

Stakeholders are invited to comment on the OIR as described in the schedule above. All comments will be served to the DRP (R.14-08-013) and IDER (R.14-10-003) proceeding service lists. We direct stakeholders to limit their comments to the schedule, the appropriateness of the list of preliminary scoping issues set forth above, anticipated activities in this proceeding, preliminary determinations below, and the following questions in their written comments and at the scoping workshop:

1. How should the proceeding schedule and tracks be managed? Should the tracks be reorganized, and if so, how? Comments may include whether to amend the issues presented in the OIR and how to prioritize the issues to be resolved; how to procedurally address these issues; and a proposed schedule for resolving the issues that may extend beyond 36 months. Please also address to what extent the tracks should be run in parallel or sequentially, taking into consideration stakeholder capacity to participate in multiple tracks at once.
2. Should the Commission address Track 1 (DSO) issues with a consultant-led process that includes a white paper followed by workshops and culminates in a third-party consultant report of recommendations? If not, how should Track 1 issues be addressed?
3. Should the Commission address Track 2 (DPP) issues through a series of consultant technical reports supplemented by workshops and followed by staff proposals? If not, how should Track 2 issues be addressed?

4. Should the Commission address Track 3 (smart inverter operationalization, grid modernization, and GRC alignment) issues in two separate work streams: 1) a smart inverter working group and working group report followed by a staff proposal and workshop, and 2) a staff-led proposal and workshop on grid modernization and GRC alignment? If not, how should Track 3 issues be addressed?

Comments shall be limited to 25 pages per party and will help to inform the Scoping Memo.

9. Respondents

Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company, shall be respondents in this proceeding. Within 15 days of mailing of this rulemaking, each respondent shall inform the Commission's Process Office of the contact information for a single representative, although other representatives and persons affiliated with the respondents may be placed on the Information Only service list.

10. Coordination with Related Proceedings and Service of OIR

We intend to coordinate this rulemaking with other related proceedings including, but not limited to, those identified in Table 1. At this time, it is anticipated that coordination will be prioritized with the Transportation Electrification (R.18-12-006), Microgrids and Resiliency (R.19-09-009), and Interconnection proceedings (R.17-07-007). Coordination needs and priorities are expected to change throughout the proceeding.

This OIR shall be served on all respondents. In addition, in the interest of broad notice, this OIR will be served on the official service lists for the following proceedings:

Table 1. Related Proceedings and Service of OIR

	Docket	Proceeding Number
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1	Emergency Summer Reliability, Extreme Weather	R.20-11-003
2	Clean Energy Financing Options for Electricity and Natural Gas Customers	R.20-08-022
3	Net Energy Metering	R.20-08-020
4	Self-Generation Incentive Program	R.20-05-012
5	Integrated Resource Planning	R.20-05-003
6	Long-Term Gas System Planning	R.20-01-007
7	Electric Program Investment Charge	R.19-10-005
8	Microgrids and Resiliency	R.19-09-009
9	Direct Access	R.19-03-009
10	Building Decarbonization	R.19-01-011
11	Transportation Electrification	R.18-12-006
12	De-Energization of Power Lines in Dangerous Conditions	R.18-12-005
13	Affordability of Utility Service	R.18-07-006
14	Wildfire Mitigation Plans	R.18-10-007
15	Click-Through Authorization Process (Demand Response)	A.18-11-015, et. al
16	Climate Adaptation	R.18-04-019
17	Streamlining Interconnection of Distributed Energy Resources and Improvements to Rule 21	R.17-07-007
18	Electricity Integrated Resource Planning Framework and Long-Term Procurement Planning Requirements Refinement	R.16-02-007
19	Energy Savings Assistance and California Alternate Rates for Energy Programs	A.14-11-007, et al.
20	Integrated Distributed Energy Resources	R.14-10-003
21	Distribution Resources Plans	R.14-08-013
22	Energy Efficiency	R.13-11-005 and A.17-01-013, et al.
23	Demand Response Enhancement Rulemaking and Program Applications	R.13-09-011 and A.17-01-012, et al.

In the interest of providing broad notice about this OIR, it will also be served on the following entities:

- California Air Resources Board
- CEC

- California Independent System Operator
- Governor’s Office of Business Development
- State Board of Forestry and Fire Protection (CAL FIRE)
- California Office of Emergency Services
- California Department of Fish and Wildlife
- California Office of Planning and Research
- California Infrastructure and Economic Development Bank
- California State Association of Counties
- California Native American Heritage Commission and the tribal contacts list maintained by the Native American Heritage Commission
- California Municipal Utilities Association
- Disadvantaged Communities Advisory Group⁶⁸
- League of California Cities
- Office of Energy Infrastructure Safety⁶⁹
- Rural County Representatives of California

Service of the OIR does not confer party status or place any person who has received such service on the Official Service List for this proceeding.

11. Filing and Service of Comments and Other Documents

Filing and service of comments and other documents in the proceeding are governed by the Commission’s Rules of Practice and Procedure. This proceeding will follow the electronic service protocol set forth in Rule 1.10. All parties to this

⁶⁸ Formation of the Disadvantaged Communities Advisory Group was called for in Senate Bill 350, the Clean Energy and Pollution Reduction Act of 2015. The 11-member group meets several times a year to review Commission and CEC clean energy programs and policies to ensure that disadvantaged communities, including tribal and rural communities, benefit from proposed clean energy and pollution reduction programs.

⁶⁹ The Commission’s Wildfire Safety Division will transition to the California Natural Resources Agency in Summer 2021 and become the Office of Energy Infrastructure Safety.

proceeding shall serve documents and pleadings using electronic mail, whenever possible, transmitted no later than 5:00 p.m., on the date scheduled for service to occur. Rule 1.10. requires service on the ALJ of both an electronic and a paper copy of filed or served documents. When serving documents on Commissioners or their personal advisors, whether or not they are on the official service list, parties must only provide electronic service. Parties must not send hard copies of documents to Commissioners or their personal advisors unless specifically instructed to do so. In addition, pursuant to the COVID-19 Temporary Filing and Service Protocol for Formal Proceedings, the Rule 1.10(e) requirement to serve paper copies of all e-filed documents to the ALJ is suspended until further notice.

12. Addition to Official Service List

Addition to the official service list is governed by Rule 1.9(f) of the Commission's Rules of Practice and Procedure.

Respondents are parties to the proceeding (see Rule 1.4(d)) and will be immediately placed on the official service list.

Any person will be added to the "Information Only" category of the official service list upon request, for electronic service of all documents in the proceeding, and should do so promptly in order to ensure timely service of comments and other documents and correspondence in the proceeding. (See Rule 1.9(f).) The request must be sent to the Process Office by e-mail (process_office@cpuc.ca.gov) or letter (Process Office, California Public Utilities Commission, 505 Van Ness Avenue, San Francisco, California 94102). Please include the Docket Number of this rulemaking in the request.

Persons who file responsive comments thereby become parties to the proceeding (see Rule 1.4(a)(2)) and will be added to the "Parties" category of the

official service list upon such filing. Additionally, persons who appear at the PHC may request party status to become parties to the proceeding and be added to the “Parties” category of the official service list. *In order to assure service of comments and other documents and correspondence in advance of obtaining party status, persons should promptly request addition to the “Information Only” category as described above; they will be removed from that category upon obtaining party status.*

13. Subscription Service

Persons may monitor the proceeding by subscribing to receive electronic copies of documents in this proceeding that are published on the Commission’s website. There is no need to be on the official service list in order to use the subscription service. Instructions for enrolling in the subscription service are available on the Commission’s website at <http://subscribecpuc.cpuc.ca.gov>.

14. Intervenor Compensation

Intervenor Compensation is permitted in this proceeding. Any party that expects to claim intervenor compensation for its participation in this Rulemaking must file a timely notice of intent to claim intervenor compensation. (See Rule 17.1(a)(2).) Intervenor compensation rules are governed by Section 1801 *et seq.* Parties new to participating in Commission proceedings may contact the Commission’s Public Advisor.

15. Public Advisor

Any person interested in participating in this proceeding who is unfamiliar with the Commission’s procedures or has questions about the electronic filing procedures is encouraged to obtain more information at consumers.cpuc.ca.gov/pao or contact the Commission’s Public Advisor at

1-866-849-8390 or 866-836-7825 (TTY), or send an e-mail to public.advisor@cpuc.ca.gov.

O R D E R

Therefore, **IT IS ORDERED** that:

1. This Order Instituting Rulemaking is adopted pursuant to Rule 6.1 of the Commission's Rules of Practice and Procedure.

2. The preliminary categorization is quasi-legislative.

3. The preliminary determination is that a hearing is not needed.

4. The preliminary scope for the proceeding is as stated above.

5. The preliminary schedule for the proceeding is as set forth above.

6. Pacific Gas and Electric Company, San Diego Gas and Electric Company, and Southern California Edison Company are named as respondents and are parties to this proceeding pursuant to Rule 1.4(d) of the Commission's Rules of Practice and Procedure.

7. Pacific Gas and Electric Company, San Diego Gas and Electric Company, and Southern California Edison Company shall, and any other person may, file comments on the preliminary scope and schedule for this Order Instituting Rulemaking (OIR) no later than 45 days following the issuance of this OIR. Reply comments are due 15 days after the Energy Division-led workshop to be held in September 2021.

8. Interested persons must follow the directions of this Order Instituting Rulemaking to become a party or to be placed on the official service list as information-only.

9. Any party that expects to claim intervenor compensation for its participation in this Rulemaking must timely file its notice of intent to claim intervenor compensation pursuant to Rule 17.1(a)(2).

10. The assigned Commissioner or the assigned Administrative Law Judge(s) will have on-going oversight of the service list and may institute changes to the list or the rules governing it, as needed.

11. The assigned Commissioner and the assigned Administrative Law Judge(s) may modify the activities and schedule established in this Order Instituting Rulemaking as necessary for the efficient conduct of this proceeding.

12. Parties serving documents in this proceeding must comply with Rule 1.10 of the Commission's Rules of Practice and Procedure regarding electronic mail (e-mail) service.

13. The Executive Director will cause this Order Instituting Rulemaking to be served on all respondents and on the service lists for the following Commission proceedings: Rulemaking (R.) 13-09-011, R.13-11-005, R.14-08-013, R.14-10-003, R.16-02-007, R.17-07-007, R.18-04-019, R.18-07-006, R.18-10-007, R.18-12-005, R.18-12-006, R.19-01-011, R.19-03-009, R.19-09-009, R.19-10-005, R.20-01-007, R.20-05-003, R.20-05-012, R.20-08-020, R.20-08-022, R.20-11-003, and Application (A.) 14-11-007 et al., A.17-01-012 et al., A.17-01-013 et al., and A.18-11-015 et. al.

This order is effective today.

Dated _____, at San Francisco, California.