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BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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

OPENING COMMENTS OF PACIFIC GAS AND ELECTRIC COMPANY (U 39 E) ON ORDER INSTITUTING RULEMAKING TO MODERNIZE THE ELECTRIC GRID FOR A HIGH DISTRIBUTED ENERGY RESOURCES FUTURE

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Pursuant to the *Order Instituting Rulemaking to Modernize the Electric Grid for a High Distributed Energy Resources Future* (OIR), issued on July 2, 2021, Pacific Gas and Electric Company (PG&E) submits these comments on schedule, scope, and preliminary determinations of this proceeding.

I. GENERAL COMMENTS: PG&E SUPPORTS THE OIR'S GOAL OF ENABLING UTILITIES TO SUPPORT A FUTURE WITH HIGH LEVELS OF DER

This OIR serves a critical policy function: to prepare our distribution operations, planning and investments for a future with increased distributed energy resources (DERs) and corresponding complexities (DERs as both load and generation). PG&E supports this objective and looks forward to working with the Commission and stakeholders on how to plan for this high DER future. In support of this OIR, PG&E also provides the following general comments that should be considered as the final scope is determined.

This OIR will be instrumental in preparing PG&E for its critical role as the distribution system owner, planner, and operator in a high DER future. PG&E is committed to preparing the grid in a way that will enable the use of DERs to optimize their value to the system. PG&E has the direct knowledge and experience with distribution ownership, operations, and planning necessary to ensure that the outcomes of the OIR are actionable. Therefore, PG&E requests additional opportunities for the utilities in this OIR to develop reports and proposals, drawing on their unparalleled experience in balancing the priorities of safety, reliability, affordability and clean energy for all customers. A proactive role for PG&E that integrates, enables, and uses DERs as a planner and operator for the distribution system will help ensure that overall system needs and objectives are addressed (e.g., safety, reliability, environmental protection), while reducing redundancies and costs to the system and customers as whole. PG&E supports the OIR's focus on the needs of a high DER grid, and how utilities' distribution planning and operations can partner with DER providers, the California Independent System Operator (CAISO), aggregators, and communities to continue to provide safe and reliable service equitably to all customers.

PG&E agrees that the purpose of the OIR should be to "determine how to optimize the integration of millions of DERs within the distribution grid while ensuring affordable rates" and that "DER integration optimization within the context of the transmission grid is also relevant."[1/] DERs are a critical tool in addressing the needs of a complex energy system, and the use of DERs should therefore be incorporated directly into the distribution planning and operation processes. Successful integration of DERs will require accompanying grid investment to fully enable DER capabilities, including grid upgrades for telemetry and operations infrastructure. DERs have proven to be an important element in California's efforts to meet its GHG reduction goals and will continue to be so. However, they alone are not enough to meet California's overall environmental and reliability goals.[2/] Investments in transmission, generation, and storage assets will also be needed to bring the greatest value to customers and provide reliable capacity. Therefore, the costs to integrate and enable DERs should be considered in the context of the broader portfolio of resources available to meet customer needs and balanced with the purpose of ensuring affordable rates.

1/ OIR, pp. 9-10.

2/ Even under a high DER penetration scenario, there is still substantial need for accompanying investment in utility-scale renewable generation that relies on large-scale transmission expansion to meet SB 100 goals. See: Wu, G.C, et. al. Power of Place: *Land Conservation and Clean Energy Pathways for California,* p. 42. Available online: https://www.scienceforconservation.org/assets/downloads/Technical_Report_Power_of_Place.pdf.

PG&E also supports that the 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"[3/] The OIR is instead focused on ensuring the operations and planning of the grid will integrate DERs in a manner that will provide value to all customers and the grid. Therefore, DER tariffs, pricing, and procurement should remain outside the scope of this proceeding.

II. COMMENTS ON PROPOSED SCOPING ITEMS

This OIR aims to prepare the electric grid for a high number of DERs. PG&E believes that most proposed scoping questions in this OIR, with some clarifications, are appropriate to achieve this proceeding's goals. However, given the broad scope, it will be critical to narrow the scope on distribution planning and operations and avoid conflicts or duplications with other DER activities identified in the Energy Division's draft DER Action Plan 2.0.

To prepare the electric grid for a high number of DERs, this proceeding proposes to consider developing frameworks or processes for distribution operations, planning, or investment. These frameworks or processes should be nimble and streamlined. DER growth may occur at different rates across PG&E's service territory. There will likely be advances in new technologies. This dynamic future warrants operations, planning, and investment flexibility. PG&E and other public utilities have the resources, knowledge, and infrastructure to implement these processes. Therefore, the OIR should focus on defining the desired outcomes and providing a flexible framework for the utilities to implement. PG&E recommends that the general scoping questions that apply to all tracks[4/] include a third scoping question to prioritize and emphasize the importance of flexible and streamlined processes to be successful in a high DER future.

While PG&E supports the majority of the proposed scoping items, PG&E recommends that a few scoping items be removed or addressed in other Commission proceedings. Comments

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3/ OIR, p. 10.

4/ *See* Id, p. 16: "General Questions Relevant to All Tracks" (*i.e.,:* 1. consideration of ESJ Action Plan goals; and 2. examining the definition of a DER).

on the specific scoping items of each track are provided below. A proposed redline to these scoping items is presented in Appendix A.

A. Track 1: Distribution System Operator Roles and Responsibilities

PG&E's interpretation of the OIR's goal for Track 1 is to investigate Distribution System Operation (DSO) models, roles and responsibilities, and implementation feasibility to determine if there could be improvements to the economic and operational value DERs can provide to the electric system.[5/] The results of that investigation would then be presented to the Commission, with findings rolled into a successor proceeding.[6/] PG&E is actively taking steps towards operating as a DSO and has significant further investments planned per its 10-year vision for Grid Modernization in PG&E's 2023 General Rate Case (GRC) filing. For example, PG&E has embarked on a multi-year, strategic grid modernization effort which is focused on consolidating its distribution operational technology platforms into a single platform: an Advanced Distribution Management System (ADMS). This is a multi-phased program that will improve situational awareness for the Distribution Operator. PG&E supports the Commission's initiative to proactively examine the DSO role needed to support a high DER future, given the continued adoption of DER technologies, notably electric vehicles with possible vehicle-to-grid integration capabilities. The Commission should take an implementation-focused approach (*i.e.*: what is needed to implement DSO models that can meet California's goals, and what is the customer impact), rather than produce additional abstract technical papers, of which there are already many on this topic. In other words, a guiding principle should be that scoping questions are framed to produce findings of fact and conclusions of law on which the Commission can make its policy decisions that inform future ratesetting proceedings.

The Commission should also consider the necessary interaction and coordination between federal and state laws and regulations when considering the role of the DSO. For example,

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5/ OIR, p. 14.

6/ Id., pp. 14-15.

FERC Orders 841 and 2222 required the California Independent System Operation (CAISO) to adopt tariff amendments that allow storage and DER aggregations (DERAs), respectively, to participate in federally-regulated wholesale markets. In its recent tariff amendment filed at FERC to implement FERC Order 2222, the CAISO recognized "it is critical to continue to work with local regulatory authorities, distribution companies, developers, and affected stakeholders to enhance the DERA model so DERAs can participate efficiently in the wholesale markets."[7/] The use of the state-regulated distribution system to access wholesale markets in a way that does not impair the stability of the distribution system and that fairly allocates the costs of distribution system upgrades to accommodate high levels of DER participation in those markets is likely to be discussed as part of these federal-jurisdictional proceedings and must be coordinated with this OIR.

1. DSO Scoping Items Should be Reframed to Focus on How the Utility as the Distribution Planner, Owner, and Operator Can Facilitate and Support a High DER Future.

To achieve a more practical understanding of DSO models for California policy purposes, PG&E recommends reframing several scoping items. First (Scoping Item 1.1[8/]), the question should not be whether the Commission "should" investigate how to redefine electric distribution roles and responsibilities, but rather present an affirmative question on "what" are the electric distribution roles that will exist in a high DER future, how are these defined, how do these roles interact, are these roles universally relevant[9/], and how can these roles be organized to best provide customers with safe, reliable, affordable, and clean electric service. While the scope should address market power and open access issues, it is important that the framing includes

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7/ CAISO Tariff Amendment to Comply with Order No. 2222, filed in FERC Docket ER21-2455, July 19, 2021, p. 3

8/ Note: references to Scoping Items are presented as "#.#" to refer to Track X, Question X.

9/ For instance, this Track should consider the geographic location of DER deployment, whether the benefits of DSO capabilities will be concentrated in specific locations, and at what DER penetration threshold these new DSO capabilities are needed.

PG&E's role as the architect of a safe, resilient, and reliable distribution system that actively balances demand and supply to enable deep decarbonization.

Second (Scoping Item 1.2), PG&E agrees that it is critical to understand the impact of the high DER future on customers – especially in ESJ communities, including the geographic distribution of DER deployment, cost-effectiveness of investments necessary by the DSO to support a high number of DERs, and the fairness of cost allocation to customers. Per OIR Appendix C, Item H ("As grid defection becomes more cost effective, it could become more common, which would increase costs for those that remain connected"), PG&E agrees that understanding the cost effectiveness of DSO models and cost impacts of high DER penetration should be a key output from this Track. It is critical for the ultimate end-product from Track 1 to include a Finding of Fact stating the direction and magnitude of costs to customers (both participating and non-participating) of various DSO models to ensure equity in cost allocation as well as transparency and sustainability of such rate impacts.

Third, PG&E recommends reframing Scoping Item 1.4 and 1.5 to focus on enabling utilities, DSOs, and aggregators to utilize DERs to provide value to the grid and reduce costs for all customers, rather than focusing exclusively on utility incentives. PG&E does not believe that a lack of utility-incentives is impeding the advancement of DER deployment and integration. Therefore, the scope should also continue the efforts from the Distribution Resources Plan (DRP) proceeding (R. 14-08-013)[10/] on how to enable utilities to directly invest, own, and operate DERs as distribution assets. This OIR's Appendix C, Item G states: "DER value streams remain untapped (e.g., energy and ancillary services, greenhouse gas costs/credits, and resiliency)." The scope should focus on defining what services DERs provide that are untapped and how utilities, DSOs, and aggregators can enable the DERs to provide value to the distribution grid.[11/] This

10/ IOU ownership bids are encouraged in the DIDF process and could be incorporated more directly into the DPP.

11/ Note: this proceeding should not focus on how to quantify the value of these services, but rather focus on how to enable DER participation so that any potential value can be provided to the grid.

scope is supported by the *DRP Retrospective Notes,* which stated that "the DRP has successfully maintained a focus on value, working to identify which DERs save money and which ones do not. This focus should be nurtured."[12/] Thus, in coordination with efforts in the Rule 21 proceeding (R.17-07-007), the scope should focus instead on how to enable DER services (by aggregators, DSOs, and the utilities).

2. DSO Scoping Items Should Not Be Overly Broad or Presume Outcomes.

PG&E recommends eliminating scoping items that use undefined terms and unsupported objectives. Scoping Item 1.3 is problematic because the "grid architecture discipline" is not clearly defined and is potentially too broad to provide a meaningful outcome or recommendation for the Commission to consider. Furthermore, as framed, this scoping item presupposes that optimizing distribution investments to accommodate a high number of DERs is the correct objective function; PG&E feels, and possibly other stakeholders may feel, this is too narrow of an objective function. Distribution investments and operations must optimize for a complex set of functions, including safety, reliability, resiliency, affordability, equity, and environmental stewardship. PG&E believes that the core purpose of Track 1 can be accomplished without Scoping Item 1.3. Eliminating this item will also allow stakeholders to focus on more concrete scoping questions with directly actionable outcomes.

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

The OIR's proposed Track 2 would take a broader look at utilities' distribution planning processes (DPPs) to improve the frameworks, tools, and community engagement. PG&E supports this broad goal, especially the emphasis on developing tools to better serve the expansion in electric vehicle (EV) load on the distribution grid. This effort is substantial to complete within three years, especially when compared to the DRP proceeding. For this reason,

12/ OIR, Appendix D.

the Commission should focus on these key priorities and not re-visit nor re-work items that has already been accomplished in previous proceedings.

1. Enhancing DPP Frameworks and Tools to Incorporate DERs, and Notably EVs, Should Be The Primary Focus.

PG&E supports moving away from solely focusing on incremental improvements to the Distribution Investment Deferral Framework (DIDF), and instead, taking a holistic review of the utilities' DPPs to examine how DERs can be a part of the planning framework, and importantly, how DPP tools can be enhanced to urgently meet anticipated EV charging load and grid integration. Scoping item 2.1 could be updated to recognize that the DIDF is just one part of the DPP, and merged with scoping items 2.4 and 2.6 to begin to outline the ways in which the DPPs could be improved to better plan, integrate, and utilize DERs. The Commission will need to make sure that this effort is aligned with R.18-12-006, and not duplicative. While PG&E is already pursuing how to use DERs as part of their DPP, this proceeding can help educate stakeholders on these initiatives and work collaboratively to improve that process.

Relatedly, PG&E supports additional refinements to Integration Capacity Analysis (ICA) data and calculations to improve accuracy and usefulness for DER planning and interconnection, especially with respect to transportation electrification (TE). PG&E sees value in investigating whether the utilities should invest further in the ICA tool to increase its utilization in supporting proactive investment in distribution infrastructure with a significant long-lead time to accommodate anticipated EV loads. Similarly, investment in the load ICA tool could facilitate interconnection transparency for EV charging providers.

2. Understanding What Communities Want and Need Must be Established Before Creating Additional Processes.

The OIR Appendix C, Item D states "Distribution planning processes do not sufficiently: (a) engage the communities where grid infrastructure would be installed; or (b) gather feedback about local development and DER siting plans to adequately forecast grid needs." Based on this conclusion, the OIR proposes scoping items 2.2 and 2.3, aimed at creating new processes to improve community engagement.

PG&E looks to continuously improve our partnership with the cities, counties, and tribes we serve concerning all planning and operations activities. In other words, engagement with our communities is not limited to the distribution planning process. PG&E's concern with the framing of scoping item 2.2 and 2.3 is that it aims to establish processes before determining what our communities want and need, and may create more burden for communities' resources, especially if not coordinated with all other utility engagement efforts (ex: on Public Safety Power Shutoff initiatives, community microgrid programs, regionalization efforts, etc). Instead, PG&E recommends that these questions be reframed to focus on determining what communities want and need and how the utilities can adopt specific criteria in their broader engagement plans to serve their communities better.

With respect to the GO 131D and DIDF process, PG&E agrees that this OIR is an appropriate forum to clarify the interaction of electric grid projects that require a CPUC permit with the DIDF process. PG&E has provided extensive comments on this issue in the original DRP proceeding and encourages the Commission to provide additional opportunities to comment on how this issue should be addressed in the DIDF. PG&E disagrees, however, that GO 131D, which establishes standards and procedures for the siting and construction of electric transmission and distribution projects, should be modified for this purpose.

3. Determining Improvements to the DPP will be more Efficient and Successful by Eliminating Issues Addressed By or Better-Suited to Other Proceedings.

The OIR proposes to revisit the types of planned investments that could be considered for deferral (scoping item 2.5), consider additional tariff pilots (scoping item 2.8(a)), and update multiple-use-application (MUA) rules (scoping item 2.8(b)). Rather than re-visit these topics, PG&E recommends that the objective of Track 2 should be to explore how the utilities' DPPs can better incorporate DERs. The types of planned investments that could be considered for deferral was the subject of Competitive Solicitation Framework Working Group in the Integrated Distributed Energy Resources (IDER) proceeding (R.14-10-003), resulting in Decision 16-12-036. This OIR should utilize the work that has already been accomplished in the IDER proceeding to advance the objectives in this proceeding, and not revisit completed initiatives.

Similarly, PG&E recommends that this proceeding focus on analyzing pilot results, and not creating additional pilots until we understand past results. The utilities are already in the process of launching two pilots (the Partnership Pilot and Standard Offer Contract Pilot) as a result of the D.21-02-006 in the IDER proceeding. This OIR's *DRP Retrospective Notes* state that "the various ongoing pilots and demonstrations should be concluded and the results should be organized into actionable takeaways."[13/] As such, the scope should prioritize understanding the results from the pilots, and how those results inform other DPP and DIDF improvements, to meet this OIR's goals. At this point in time, additional pilots may detract from using resources to analyze what is already available to make DPP improvements.

Lastly, the Commission investigated MUA rules in Rulemaking 15-03-011, instituted rules in D.18-01-003, and directed the utilities to report on the results of the subsequent MUA Working Group.[14/] In other words, a substantial portion of an entire proceeding and working group effort was dedicated to MUA issues. PG&E does not recommend attempting to take on this complex issue in this OIR, but rather in the successor storage and/or demand response OIRs, as recommended by CPUC staff in the Draft CPUC Distributed Energy Resources Action Plan.[15/]

C. Track 3: Smart Inverter Optimization, Grid Modernization, and GRCs

The OIR proposes to address Grid Modernization issues and Smart Inverter Optimization (SIO) implementation in a single Track 3. PG&E generally supports both efforts, but notes that

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13/ OIR, Appendix D.

14/ See *Compliance Report of Southern California Edison, Pacific Gas and Electric Company, and San Diego Gas & Electric Company on Behalf of the Multiple-use Application Working Group*, filed August 9, 2018 in R.15-03-011.

15/ See "DER Action Plan 2.0" p.23. Available online at: https://www.cpuc.ca.gov/about-cpuc/divisions/energy-division/der-action-plan. Issued July 23, 2021.

they are discrete issues, and could be separated into two separate tracks.

1. Grid Modernization Framework Improvements Are Appropriate But Should Not Apply to Pending or Active GRCs, and Should Be Coordinated with the Upcoming TEF Decision and TE Plans.

PG&E supports revisiting the Grid Modernization framework for minor updates but requests that the Commission be explicit that the proceeding does not impact pending or active GRCs. Any major updates would not be able to apply until PG&E's 2031 GRC. This timing issue is discussed in more detail in Section III.C, below. That said, PG&E agrees that this proceeding should investigate whether any updates are needed and whether additional alignment is needed between DPPs and the GRC,[16/] as indicated by scoping items 3.1, 3.2, and 3.5.

With respect to scoping item 3.2, PG&E recommends reframing the questions to inquire whether the classification table of Grid Modernization investments[17/] be updated to accommodate anticipated future GRC investments in TE technology categories (e.g., Vehicle-to-Grid (V2G) controllers) that enable the provision of grid services or two way flows of electricity. Other types of GRC investment to accommodate EVs include standard distribution capacity and expense that do not meet the definition of "Grid Modernization" investments. Reframing the question in this manner will eliminate ambiguity on the definition of a Grid Modernization investment.

With respect to scoping item 3.2, PG&E is concerned that is it too early to know how much overlap there might be between TE Plans and Grid Modernization Plans. The CPUC is expected to provide final guidance for IOUs to develop ten-year TE Plans once it approves a final Transportation Electrification Framework (TEF). Once a final TEF is approved, the utilities will develop ten-year TE Plans that will likely take 6-12 months to propose. Approval of such TE Plans may then take another 6-12 months. The scope of this proceeding should not

16/ For example, D.18-02-004's directives are based on a GRC filing date in September, however GRCs are now filed earlier in the year, prior to the annual GNA and DDOR reports. Revisiting these alignment issues could be beneficial to ensure compliance with the Commission's goals.

17/ D. 18-03-023, Appendix B

presuppose the final guidance in the TE Plans. Instead, the scope could focus on how TE technology should be incorporated in Grid Modernization plans *once* the TEF is established.

2. Specific Investment Priorities in GRCs Should be Driven by Utilities, Not the Grid Modernization Framework.

Scoping item 3.3 suggests that the Grid Modernization framework develop investment priorities for utilities' GRCs. PG&E respectfully requests that this item be removed from the scope of this OIR. Utilities should retain flexibility and autonomy in determining the substance and timing of their Grid Modernization investment proposals, as utilities are responsible for prioritizing and managing their GRC funding requests to keep costs manageable for customers. As discussed earlier, the utilities are responsible for planning, building, and operating a complex electric (and gas) system. Funding must be allocated based on the highest priority needs. Accordingly, proposed scoping item 3.3 should be removed.

3. A Track 4 on Smart Inverter Optimization Should Focus on Implementation.

PG&E recommends moving scoping item 3.4 to a separate Track 4, as this is an independent issue and could have its own timeline. Furthermore, the stakeholders that are interested in Grid Modernization may be different than those interested SIO, just as the internal subject matter experts on these topics are distinct. Maintaining these separate topics in the same track can make communicating the issues more challenging.

The SIO Track 4 should focus on implementation of smart inverter functionalities as established in the Rule 21 proceeding (R.17-07-007). PG&E recommends that this scoping item be focused on enabling the use of smart inverters by implementing functionality and developing guidelines for utilities and aggregators on the use of smart inverters, rather than a discussion on payment for services which are not yet enabled. This scoping item should also address the cybersecurity requirements and protocols to enable SIO while protecting grid assets and customers.

III. PROCEEDING SCHEDULE AND MANAGMENT

The OIR's proposed timeline appears feasible and appropriate, especially if the scope is revised to address the key issues as recommended above. Overall, PG&E requests greater involvement by the utilities in developing reports and proposals, as the utilities have the direct knowledge and experience with distribution ownership, operations, and planning. Energy Division and its consultant should continue to play a substantial role in providing proposals and facilitating workshops and stakeholder feedback. PG&E's refinements to the proceeding schedule and management is described below, with a timeline provided in Appendix B.

A. Track 1

PG&E agrees that investigating the DSO roles and responsibilities in a high DER future (including how those roles interact and how these roles can be organized to best provide customers with safe, reliable, affordable, and clean electric service) could benefit from a technical report to kick off the initiative. Thereafter the process should allow for utility and voluntary stakeholder proposals based on the Energy Division's consultant's technical report, that could be presented at working group meetings and followed by comments and reply comments. Energy Division and its consultant could facilitate the working groups, culminating in a Technical Report and Proposed Decision accelerated to as early in 2023 as feasible so that it can inform the other tracks. The Locational Net Benefits Analysis Working Group and ICA Working Groups facilitated by Gridworks is one example of how Track 1 could be organized.[18/] This process was well-organized, ensured ample opportunity for stakeholder participation, and created a clear record of the discussion topics, including consensus and non-consensus items upon which the Commission could issue findings of fact to support a decision on next steps.

Scoping item 1.5 proposes to address "what policies could the Commission adopt quickly" to enable aggregators. Aggregators will likely play a key role in a high DER future. Collaboration between the utilities, aggregators, and key stakeholders will be critical to

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18/ See Gridwork's working group process and results at https://drpwg.org/sample-page/drp/.

developing guidelines, processes, and requirements for aggregators. PG&E recommends that the timeline for this item be extended to allow for a working group process suited for extensive collaboration and involvement by multiple parties.

B. Track 2

PG&E believes that a key to success in enhancing the utilities' DPPs is to actively involve the utilities in the proposal and workshop process. For instance, the "Phase 1 electrification impacts on distribution planning Technical Report and Workshop" that would forecast the scope and cost of grid impacts, scheduled for Q3 2022,[19/] will require utility data and inputs. PG&E recommends that this report be a collaboration between Energy Division and the utilities, and that each utility would present its scope and cost impacts at the workshop. Similarly, the "Phase 2 electrification impacts report"[20/] would include utility proposals in addition to the staff proposal on how the distribution planning process can mitigate grid impacts identified in each utilities' Phase 1 report. Ultimately, the utilities are best suited to understand the existing DPPs and where reforms to frameworks and tools are possible and appropriate to address TE.

PG&E also recommends converting the Q4 2022 Energy Division Workshop on DPP improvement to a utility-led workshop on community engagement. This workshop would enable the utilities to educate stakeholders on existing engagement processes and receive feedback from stakeholders on community wants and needs.

The DRP Data Portals and ICA are valuable tools for TE efforts. PG&E recommends amending the proposed schedule to include a workshop with utility proposals for Data Portals and ICA enhancements (as well as Energy Division or stakeholder proposals) as early as Q1 2023. The proposals and comments could inform the subsequent DPP Guidelines proposals and future investment decisions in the DRP Data Portals and ICA tools.

19/ OIR, p. 28.

20/ Id.

Ultimately, the electrification impact workshops, community engagement workshops, and ICA/Data portals workshops (and the stakeholder comments and reply comments on each), could culminate in a consultant report recommending advanced analytics and general guidelines on enabling the incorporation of DER solutions directly into utility DPPs as standard practice. As TE is a top priority to achieve California's climate goals, PG&E recommends aiming to have a proposed decision on this Track by Q2 2024.

C. Track 3 – Grid Modernization and GRCs

PG&E supports focusing on minor Grid Modernization updates later in this proceeding to ensure that the TEF and TE Plans have progressed sufficiently to evaluate the appropriate scope of TE investments in the Grid Modernization category. If a decision is issued by mid-2024, PG&E will be able to incorporate minor changes to Grid Modernization directives in testimony for the May 2025 filing date for PG&E's 2027 GRC. However, based on this timeline, any major changes to the Grid Modernization framework could not be incorporated until PG&E's 2031 GRC.

Consistent with Tracks 1 and 2, PG&E recommends that this Track 3 include utility proposals alongside any staff proposals. Generally, utilities are best suited to draft proposals on TE needs, because of their engagement in ongoing pilots and technology testing. The utilities and Energy Division proposals should be preceded by a round of opening comments, followed by updates to the proposals based on the comments and workshop feedback. The updated proposals would also include comments and reply comments, upon which the Commission could issue a proposed decision by the latter half of 2024.

D. Track 4 – Smart Inverter Optimization

PG&E generally agrees with the proposed schedule to prioritize SIO in 2022 and recommends that Energy Division and its technical consultants facilitate the working groups and reporting on consensus and non-consensus items. This would help provide a neutral third party to gather proposals from stakeholders and the utilities, and lead discussion among parties to try and find consensus if possible. After the final report is issued, Energy Division, the utilities, and any interested stakeholders could submit proposals. After comments and reply comments on the proposal, there could be a proposed decision as early as mid-2023.

IV. CATEGORIZATION AND HEARINGS

PG&E agrees that the scope of this proceeding, as proposed above, addresses policy issues that can be categorized as quasi-legislative. To the extent that the scope includes additional pilots, the categorization should be revisited to determine if a ratesetting classification is appropriate. If there is adequate opportunity for utility proposals followed by comments and reply comments to provide a full record, PG&E agrees that no hearings are necessary.

V. CONCLUSION

PG&E appreciates the opportunity to provide feedback on the proposed scope of this important and ambitious proceeding and looks forward to discussing further at the Prehearing Conference and September workshop.

Respectfully Submitted,

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Appendix A

PG&E's recommendations are presented as follows:

- Underlined text should be added; and
- ~~Strikethrough~~ text should be deleted.

General Questions Relevant to All Tracks

1. How could this proceeding advance or challenge achievement of the nine ESJ Action Plan goals?
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.
3. How can the frameworks and processes developed in this OIR be dynamic to address variable DER deployment (in volume and geography), nimble (to accommodate system changes), and streamlined (maximize administrative efficiencies)?

Track 1: Distribution System Operator Roles and Responsibilities -

1. ~~Should the Commission investigate how to redefine electric distribution IOU~~ What roles and responsibilities are required to successfully plan and operate a high DER grid, how are those roles defined, how do the roles interact and appropriately limit market power~~,~~ and ensure open access for DER providers and aggregators offering retail and wholesale grid services, and which DSO model is best to serve customers with safe, reliable, affordable and clean electric service? ~~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? How do differences in the geographic deployment of DERs impact ratepayers? What is the direction and magnitude of costs to both participating and non-participating ratepayers? How do we compare the cost effectiveness of various DSO models and ensure equity in cost allocation, transparency, sustainability, and access in each model?

~~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~~3. What services can DERs provide that remain untapped and could provide value to the distribution grid? Should the IOUs be incentivized to cost-effectively prepare for widespread DER deployments? If so, how?

~~5~~4. What policies could the Commission adopt ~~quickly~~ to enable aggregators to provide the value of DER services to the grid and customers? ~~increase the scope of services they provide the distribution grid?~~

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

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 better consider and plan for DERs? In what was 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. What are cities, counties, and tribal communities wants and needs for involvement in the IOU DPPs? How can the IOUs ensure community wants and needs are addressed? How can these engagement efforts be coordinated with existing engagement activities? ~~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?~~

~~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)?~~

~~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 virtual power plants that provide community benefits like equity and resiliency? 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?~~

~~f.~~ How can ~~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 phase (when there is already a filing at the Commission in active review).

4. How should the DPP/DIDF processes improve to support widespread TE?

g. ~~What improvements to~~ Can GNA load forecasting ~~can be made~~ be used to identify grid investments needed to support TE goals? If so, what changed are necessary? 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) as opposed to high numbers of dispersed level 1 and level 2 EVSE?

h. What coordination is needed between the Commission, CEC, and CAISO to improve the use of EV forecast data for distribution planning purposes?

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?

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. 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~~5. How can IOUs educate and work collaboratively with stakeholders about its existing efforts to ~~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~~6. ~~How s~~Should investments be made in ICA data and calculations so that it can be ~~improved to enhance accuracy and usefulness~~ used for DER planning and interconnection (especially with respect to TE)?

k. Should we incorporate annual load forecast as input to load ICA similar to what PG&E uses in its GNA assumptions? ~~Should ICA data be aligned with annual GNA load forecast results? If so, how and with what objective?~~

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?~~

m. ~~How should~~ Could the IOUs' DRP Data Portals (including the ICA tool) be ~~improved and better coordinated~~ used with other proceedings~~? For example~~ such as, 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) pursuant to DRP proceeding decisions on confidentiality.

~~8~~7. What are the key takeaways from the DRP demonstration pilots, IDER incentive pilot, and ongoing Partnership Pilot and Standard Offer Contract pilots? How can these learnings be leveraged to inform DPP improvements? ~~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 pilot~~)? Consider the evaluation of ongoing pilots in response to this question.

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

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. Do utilities anticipate future GRC investments in categories of TE-related technology that enable provision of grid services or two-way flows of electricity, and should the classification table of Grid Mod investments (D. 18-03-023, Appendix B), be updated accordingly? ~~Should TE needs be updated in the IOU Grid Modernization Plans?~~ If so, once a final TEF decision is issued in R.18-12-006, how, and in what ways should the Grid Modernization Plans be coordinated with IOU TE plan filings established by the TEF?

~~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?~~

~~5~~3. How can the ~~planned investments identified in the~~ annual DDOR and DPP be further aligned with ~~investments proposed and approved in~~ the quadrennial GRCs to reduce ratepayer costs and provide maximum value to ratepayers?

Track 4: Smart Inverter Operationalization

41. 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 Four be ~~accomplished such that DERs, utilities, and aggregators fully leverage~~ implemented to enable smart inverter advanced functionality to provide grid services that are safe and improve reliability and resiliency? What are the cybersecurity requirements for operationalization?

Appendix B
Proposed Schedule

	Track 1	Track 2	Track 3	Track 4
Q1 2022	DSO roles and responsibilities **White Paper and Workshop** on scope of technical report			SIO Working Group convenes
Q2 2022		**DIDF Guidelines** document and comments		
Q3 2022	Working Group 1: Proposals for DSO models to meet needs of High DER future in California	Phase 1 Electrification Impacts **Report and WS - Joint IOU/ED**: Scope and Cost of Grid Impacts. Comments and Reply		
Q4 2022	WG 1 Comments	**IOU Workshop** on Community Engagement; comments/reply comments		SIO Working Group Final Report
Q1 2023	Working Group 2: Aggregator roles in DSO Models; Aggregator Services	**IOU and Staff Proposals and WS** for ICA and Data Portals Improvements; comments and reply comments		Staff, Utility, and Stakeholder Proposals on SIO; comments/reply comments
Q2 2023	WG 2 Comments	Phase 2 Electrification Impacts **Proposals and WS** - **IOU, Staff, and Stakeholder** proposals for how to improve distribution planning to mitigate grid impacts identified in Phase 1; comments and reply		**Proposed Decision**
Q3 2023	Working Group 3: Equity, Cost Effectivess, and Cost Allocation		**Staff and IOU Proposals and WS** on grid mod improvement and GRC alignment	
Q4 2023	WG 3 Comments	**Staff/Consultant Proposal** for DPP Guidelines	Comments	
Q1 2024	Working Group 4: Miscellaneous/revisit WG topics; WG 4 comments	Comments & Reply	**Revised Proposals and WS** based on Comments	
Q2 2024	Final Working Group Report	**Proposed Decision** on DPP Guidelines	Comments on Updated Grid Mod Framework Proposals	
Q3 2024	**Techinical Report** summarizing WG **consensus and nonconsensus items for DSO**			
Q4 2024	**Proposed Decision** on DSO roles		**Proposed Decision**	