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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769.	Rulemaking 14-08-013
And Related Matters.	Application 15-07-002 Application 15-07-003 Application 15-07-006
NOT CONSOLIDATED	
In the Matter of the Application of PacifiCorp (U901E) Setting Forth its Distribution Resource Plan Pursuant to Public Utilities Code Section 769.	Application 15-07-005
And Related Matters.	Application 15-07-007 Application 15-07-008

ADMINISTRATIVE LAW JUDGE'S RULING MODIFYING THE DISTRIBUTION INVESTMENT DEFERRAL FRAMEWORK—FILING AND PROCESS REQUIREMENTS

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Summary

The *Administrative Law Judge's Ruling Modifying the Distribution Investment Deferral Framework Process* issued on April 13, 2020 (*April 13, 2020 Ruling*) updated the Independent Professional Engineer (IPE) scope of work for the Distribution Investment Deferral Framework (DIDF) process and provided the 2020-2021 DIDF cycle schedule. This *Ruling* further modifies the DIDF process and filings requirements by focusing on the comments and reforms related to aspects of the DIDF not addressed in the *April 13, 2020 Ruling*. Given the length of this *Ruling*, I have provided an Attachment A, which identifies the list of the filing and process requirements for ease of reference.

1. Background

In Decision (D.) 18-02-004, the Commission adopted the DIDF. Building on the Competitive Solicitation Framework developed in the companion Integrated Distributed Energy Resources proceeding,[1] the DIDF established an ongoing annual process to identify, review, and select opportunities for third party-owned distributed energy resources (DERs) to defer or avoid traditional capital investments by the Investor-owned Utilities (IOUs) on their electric distribution systems. D.18-02-004 ordered the IOUs to implement the DIDF as an annual planning cycle that would result in the selection of distribution upgrades for deferral through the competitive solicitation of DERs.

The DIDF framework implemented in 2018 and 2019 with the expectation that it would be evaluated and revised after each cycle to improve the process. To that end, the assigned Administrative Law Judge (ALJ) issued a *Ruling Requesting Answers to Questions to Improve the Distribution Investment Deferral*

[1] Rulemaking (R.) 14-10-003.

Framework Process on February 29, 2019 (*February 29, 2019 Ruling*), and then modified the DIDF based on comments received in the *Ruling Modifying the Distribution Investment Deferral Framework Process* on May 7, 2019 (*May 7, 2019 Ruling)*. Parties also provided input on the DIDF process throughout the 2019 DIDF cycle, the IPE made recommendations, and staff have gained further experience with implementing the DIDF. A *Ruling Requesting Comments on Possible Improvements to the 2020 Distribution Investment Deferral Framework Process* was subsequently issued on November 8, 2019 (*November 8, 2019 Ruling*), and the contents of this *Ruling* further modify the DIDF.

Eight parties provided comments in response to the *November 8, 2019 Ruling*: California Energy Storage Alliance (CESA), California Public Advocates Office (Public Advocates), Coalition of California Utility Employees (CUE), Green Power Institute (GPI), Pacific Gas & Electric (PG&E), San Diego Gas & Electric (SDG&E), Solar Energy Industries Alliance/Vote Solar (SEIA/Vote Solar), and Southern California Edison (SCE). Based on party comments on the *May 7, 2019 Ruling* questions as well as the other sources of comments and input mentioned above, this *Ruling* make the following modifications to the DIDF. The modifications will go into effect for the 2020-2021 DIDF cycle, including the Distribution Planning Advisory Group (DPAG) process and Request for Offers (RFO) solicitations.

2. Implementation Timeframe for DIDF Reforms

The timeframe for complying with this *Ruling* may be challenging for the IOUs given the number reforms identified and the effort required to make the August 15, 2020 Grid Needs Assessment/Distribution Deferral Opportunity Report (GNA/DDOR) filing date. While the IOUs are proceeding through the required steps to develop their filings, the Commission has been advised that many IOU employees have been working from home due to the COVID-19 pandemic, and that working from home may impact each IOU's ability to meet its deadlines. Considering this development, Energy Division should hold a stakeholder workshop to receive feedback on which reforms identified in Attachment A should be prioritized for implementation in the 2020-2021 DIDF cycle, and which should be implemented in the 2021-2022 cycle (Reform No. 1). Partial implementation for some reforms should also be considered, with full implementation achieved for the 2021-2022 DIDF cycle. Unless controlled by statute or prior Commission decision, Energy Division may make adjustments to the implementation timeframe after consulting with the Assigned Commissioner and ALJ.

3. General DIDF Reform Topics

3.1. Proceeding Status

This section addresses Item 5 from the *November 8, 2019 Ruling* (*see* Attachment B to this *Ruling*).

3.1.1. Party Comments

The IOUs recommend against expanding or too drastically changing the DIDF, preferring smaller, incremental changes to the DIDF that could improve the efficiency, quality, or accessibility of the filings and improve outcomes through DER interconnection process improvements. SCE states that tools developed through the DRP, in conjunction with the DIDF, have greatly improved the IOUs' ability to plan for and identify opportunities to integrate DERs into the electric system. These new methods will continue to be included and advanced for future planning cycles. The time and resources required to significantly revise and broaden the DIDF would be better spent on revising the processes necessary to implement DERs through interconnection and operational improvements.

SCE believes that the DIDF should proceed as established in D.18-02-004, with reforms focused on minor changes through an advice letter process. If the proceeding remains open, SCE requests that changes should be proposed for comment, and followed by a workshop to discuss the proposed changes, the ability of IOUs to implement those changes and the time required to implement those changes.

SDG&E states that the success of the DIDF process should not be measured by the number of DER contracts that emerge from the annual DIDF cycle but rather in the results delivered to ratepayers. When there are savings to ratepayers from a DER cost-effectively deferring a planned distribution infrastructure investment, the DIDF has been successful. So too is the DIDF successful, says SDG&E, when a traditional wires solution is determined to be more cost-effective than a DER alternative.

SCE and SDG&E believe it may be time to close the DRP proceeding given the urgency of other priorities, such as wildfire mitigation. Policy issues remaining in DRP could be transferred to other proceedings. The DIDF process has reached a level of maturity that it can continue independent of an open DRP proceeding, says SDG&E.

In reply, CESA states that the DIDF continues to represent an effective mechanism to assess and source cost-effective DER solutions to defer traditional distribution investments. While imperfect and in need of continued improvements, the DIDF has yielded DER procurements that can serve as a learning opportunity to make additional improvements. CESA believes the DIDF should be improved to further level the playing field such that more DER solutions are identified that provide services at lower cost to ratepayers than traditional investments.

SEIA and GPI state that the DIDF continues to be a work in progress. SEIA was pleased, however, that in the most recent DIDF cycle, multiple distribution system constraints were identified by SCE and PG&E that merited consideration for DER solutions. GPI is concerned that the DIDF is not yet capable of the dependable deployment of cost-effective distributed resources that satisfy distribution planning objectives of Assembly Bill (AB) 327.

GPI opposes the SCE and SG&E recommendations to close the DRP proceeding. On the contrary, says GPI, changes are critical to ensuring the DIDF's ability to effectively integrate DER solutions into the distribution system. For example, failure to establish a suitable prioritization metric prior to closing the DRP, says GPI, will lead to DIDF cycles without progress made toward realizing AB 327 requirements. GPI is troubled by SDG&E's comments indicating that the primary objective of the DIDF is to minimize ratepayer costs.

3.1.1.1. IOU-Owned DERs that Were Not Competitively Sourced

GPI supports the disclosure of IOU-owned and operated DER solutions implemented, especially those that address near-term needs eliminated from the DIDF by the timing screen.[2] CESA also supports the disclosure of such DER solutions in the GNA/ DDOR filings, even though they would likely not represent deferrable investments for the DIDF RFOs. At this stage, states GPI, a

[2] D.18-02-004 adopts two types of initial deferral screens to identify candidate deferral shortlists. The technical screen is applied to determine whether DERs can meet the identified grid need based on the four distribution services adopted in the Competitive Solicitation Framework (D.16-12-036). The timing screen is applied to determine whether a DER solution can be deployed in advance of the forecast need date.

lack of operational knowledge regarding DERs and their ability to reliably meet grid needs appears to eliminate DERs as potential solutions to distribution grid needs. GPI states that IOU ownership details may help close the operational knowledge gap.

SEIA agrees that more information should be disclosed by each IOU about near-term projects. Whether or not it currently happens, says SEIA, it is certainly feasible for utilities to deploy DERs (either utility-owned or third-party owned) to meet near-term needs that are currently excluded by the DIDF timing screen (*i.e.*, the screening of traditional projects that address grid needs occurring within three years). For example, mobile storage units could be very quickly deployed at utility substations to mitigate near term overloads or other violations. Utilities could own and rate-base these assets to mitigate near-term issues while longer-term DER solutions are being deployed, or they could lease them from third parties.

PG&E states that it has not yet implemented any IOU-owned and operated cost effective DER solutions for near-term capacity needs currently excluded by the timing screen. SDG&E presumes that any IOU-owned DER solutions would be referenced in the DDOR.

3.1.2. Discussion

This *Ruling* does not express an opinion on what should be the timeline for closing this proceeding as that is a matter within the Commission's authority. As the parties and the Commission have gleaned, this proceeding has become more complicated and nuanced since the inception, and this is especially true with respect to DIDF. The DIDF is intended to facilitate the integration of cost-effective DERs onto the grid pursuant to AB 327. Through annual DIDF cycles, the savings and costs of DER integration continue to be identified, barriers to DER deployment are being addressed, and DERs are expected to be deployed that cost-effectively satisfy the IOUs' distribution planning objectives in comparison to traditional grid investments. Work remains to improve the DIDF process to better achieve the goals of AB 327 and associated Commission objectives as described throughout this *Ruling*.

It is important to better understand, for example, to what extent the IOUs already seek to own DER solutions outside of the DIDF process. The IOUs should include with the GNA/DDORs a comprehensive listing of all DERs not competitively sourced to address grid needs (Reform No. 2). IOU ownership as a DIDF RFO outcome is discussed in Section 6.2, IOU Ownership, and potential refinements to the timing screen are discussed in Section 4.6, Grid Needs and Deferral Screens.

3.2. Interconnection Issues

This section addresses Item IOU c from the *November 8, 2019 Ruling* (*see* Attachment B to this *Ruling*).

3.2.1. Party Comments

PG&E states that it has a study process that may allow for faster interconnection but not all projects qualify. SCE says that if DIDF Advice Letters requesting RFO launch are approved as early as possible, the IOUs and developers would gain interconnection process flexibility (*i.e.,* more freedom to the select the independent study, fast track, or queue cluster process). This is because final selection and contracting could be done in advance of the formal closure of SCE's annual interconnection queue cluster process, which commences in April.

CESA's reply acknowledges the interconnection challenges identified by the IOUs but remains hopeful the issues will be addressed in a coordinated effort with associated Commission proceedings, *e.g.*, R.17-07-007, *Rulemaking to Consider Streamlining Interconnection of Distributed Energy Resources and Improvements to Rule 21*.

3.2.2. Discussion

This *Ruling* acknowledges the ongoing interconnection challenges described by the IOUs. Solar photovoltaics or energy storage, whether utility-owned or third-party owned, go through some form of an interconnection process. The time required to procure and interconnect DERs can make it difficult to align with the timing of planned investment needs that have near-term in-service dates. These issues have not gone unnoticed at the Commission.

Solutions such as DER tariffs should be further explored because they may help to streamline the procurement process by allowing more time to complete interconnection study processes and contract execution. As the parties note, interconnection processes and policies are also being explored in the *Rule 21 proceeding*. Public Advocates points to the engineering and planning software tools requested in Grid Management Plans as part of the PG&E and SCE General Rate Cases (GRCs) that are intended to calculate integration capacity and streamline DER interconnection, among other improvements. If approved, it will take a few years to realize the benefit of these procurement tools with respect to DIDF outcomes. Furthermore, in their April 7, 2020 letter to the Commission, SCE indicates that interconnection process improvements continue to be made to expedite Rule 21 non-export storage and by expanding the use of their Grid

Interconnection Processing Tool.[3] PG&E and SDG&E will continue to find ways to streamline interconnection processes as well. SDG&E responded to Executive Director Stebbins that, "last year, SDG&E approved approximately 31,000 interconnection requests with an average approval time of 2.3 calendar days for Net Energy Metering (NEM) and 3 business days for Rule 21."[4]

Within the confines of the DIDF, this *Ruling* agrees with SCE that timely approval to launch RFOs and of executed contracts is important to the extent feasible based on the IOU filings received. Reforms are described in Section 6.1, Procurement Process Review, Monitoring, and Reporting, that should accelerate the bid solicitation and contracting processes for feasible, cost-effective DER solutions. Additional instruction is provided in Section 6.4, Day-Ahead Dispatch Requirements.

3.3. Common Comparable Datasets

This section addresses items 1, 6, IPE C, IPE R, IOU a, and IOU b from the *November 8, 2019 Ruling* (*see* Attachment B to this *Ruling*).

3.3.1. Party Comments

According to GPI, its review of the 2019 GNA/DDOR filings indicates that the IOUs did not use the same Integrated Energy Policy Report (IEPR) datasets for disaggregation. For example, SDG&E applied the California Energy Commission (CEC) Load Modifiers Mid Baseline-<u>Low</u> AAEE-AAPV CED 2017 data, whereas PG&E and SCE used the CEC Load Modifiers Mid Baseline-<u>Mid</u>

[3] April 7, 2020 *SCE Response to Alice Stebbins, Executive Director, CPUC*, regarding March 17, 2020 request to implement expected Microgrid and Resiliency Strategies Rulemaking (R.) 19-09-009 directives.

[4] March 26, 2020 *SDG&E Response to Alice Stebbins*, Executive Director, CPUC, regarding March 17, 2020 request to implement expected Microgrid and Resiliency Strategies Rulemaking (R.19-09-009) directives.

AAEE-AAPV CED 2017 data.[5] GPI recommends that all IOUs use the Mid Baseline-Mid AAEE-AAPV baseline data. GPI further recommends that the IOUs clarify in the GNA/DDORs whether the draft or updated CEC datasets were used, and that PG&E and SDG&E provide additional specificity regarding their datasets and methodologies used for DER disaggregation. GPI found the tabulated summary of grid needs in PG&E's GNA to be helpful (PG&E GNA 2019 at 15-18 and PG&E DDOR 2019 at 7-10). GPI suggests that similar summary tables covering distribution planning region, distribution type, in-service date, and project type should be provided by all three IOUs.

CESA states that it encountered difficulties with assessing SDG&E's GNA/DDOR data and documentation. To support transparency and greater accessibility to stakeholders, CESA recommends that SDG&E's filings explain differences between the GNA and DDOR related to specific facility locations and be similar, in general, to SCE's GNA/DDOR filings. The filings should be reviewable by stakeholders as standalone documents without needing or requesting additional information from the IOUs.

SEIA claims that SDG&E's overall participation in the DPAG process was poor, and that their presentation of data was inferior to that offered by SCE and PG&E. The fact that the technical screens they used produced zero cost-effective projects for consideration was suspect, says SEIA, who stresses that the IOUs adopt best common practices for the GNA/DDOR filings and presentations.

Public Advocates says SCE provided the most robust version of GNA/DDOR datasets, and PG&E and SDG&E should follow SCE's approach. That said, there remains room for SCE to improve. According to Public

[5] AAEE = Additional Achievable Energy Efficiency, AAPV = Additional Achievable Photovoltaic, and CED = California Energy Demand.

Advocates, SCE did not provide forecast facility loading data for all feeders on their distribution system in compliance with the *May 7, 2019 Ruling* at 5. Public Advocates claims its review of SCE's GNA tables indicated that forecast data was provided for 4,165 feeders, but equipment ratings and circuit loads were only provided for the 534 circuits forecast to have a deficiency. Public Advocates states that SCE's GNA tables also fail to include data for substation transformer banks as required by the *May 7, 2019 Ruling*.

SDG&E responds that where differences exist in comparison to the *May 7, 2019 Ruling* and associated DIDF requirements specific in Commission decisions, rulings, and resolutions, they are generally minor, *i.e.*, due to labeling or formatting. SDG&E's reply comments state that their 2019 filings and presentations complied with the Commission's orders, objectives, and expectations in support of the DIDF. The fact that SDG&E did not identify deferrable projects in 2019 reflects the unique circumstances and planning needs currently within SDG&E's distribution forecast. PG&E's 2019-2020 DIDF cycle produced four candidate deferral projects and SCE's identified six. SDG&E says it is critical to recognize that their service territory is barely more than one county in size but boasts more than 250 megawatts (MW) of installed customer generation capacity.

3.3.1.1. Party Comments Summary Specific to Customer Count and LNBA Information

IPE Recommendation C in the *May 7, 2019 Ruling* was not entirely clear as indicated by the comments from PG&E and SCE. SCE states that if IPE recommendation is referring to calculating the Locational Net Benefits Analysis (LNBA) for all planned investments consistent with the method used for candidate deferral projects, they strongly oppose the recommendation. This recommendation would require significant additional employee resources and planning software, says SCE, but would provide minimal value to DIDF stakeholders.

PG&E and SCE request that customer count details only be provided for candidate deferrals. PG&E asserts that providing customer composition for all Planned Investments is a significant burden on the utilities, and there is no indication that this information has been used by stakeholders to date. SCE agrees and adds that providing customer composition for candidate deferral projects may help DER developers understand DER adoption opportunities in areas where a project may be included in a DIDF solicitation.

3.3.1.2. Party Comments Summary Specific to DER-Driven Needs

GPI supports the IPE recommendation for the IOUs to provide further information regarding DER-driven needs in their GNA/DDORs. GPI believes that DER forecast disaggregation and the GNA are important for assessing the ability of the distribution grid to support increasing DER penetration. A summary of DER-driven needs, including upgraded equipment, and monitoring and control systems, will inform stakeholders and policy makers of the investments needed to support increased DER adoption and adoption patterns. Providing this information would be consistent with Integration Capacity Analysis (ICA) use case for informing and identifying DER growth constraints in the planning process, says GPI. GPI also supports increasing the connection between DIDF filings and ICA data provided on the DRP Data Portals.

SCE states that it reports DER-driven needs and projects in its annual GNA/DDOR filing, including the equipment required to mitigate the DER-driven needs. SCE says it provided the methodology used to develop the non-DER solution to DER-driven needs. SCE states that their GRC filing also describes the steps being taken to modernize the grid that accounts for many aspects such as increased sensing and operational visualization with our grid management system. SCE believes the GNA/DDOR and GRC sufficiently explain their DER-driven need methodology.

SDG&E states that DER-driven distribution needs are addressed through the Grid Modernization Framework, GRC filing, and generator interconnection process (*e.g.*, Rule 21). Large DER projects typically pay interconnection costs, not ratepayers, hence SDG&E believes there would be no generalized consumer benefit from deferring interconnection costs. SDG&E does not believe the costs associated with interconnecting DERs (*i.e.*, interconnection upgrades characterized as non-DER solutions) should be included in the GNA.

3.3.1.3. Party Comments Summary Specific to Pre-Application Project Planning Horizons

With respect to Pre-Application Projects,[6] CESA states that all transmission and sub-transmission GNA components should use a 10-year planning assumption and forecast to align with the 10-year DDOR data. SEIA agrees, adding that there are substantial potential savings from deferral of larger projects, but the non-wire solutions will also tend to be larger and more complex. Therefore, it is important that there be maximum visibility about the forecasted

[6] "Pre-Application Projects" are transmission and sub-transmission projects with associated grid needs under CPUC jurisdiction that are expected to require review pursuant to General Order (GO) 131-D. Projects filed under GO 131-D typically require review pursuant to the California Environmental Quality Act (CEQA) as well. The following three projects in the 2019 DIDF Cycle were identified that are already undergoing review pursuant to a GO 131-D application process before the CPUC: PG&E's Estrella Substation Project (Application (A.) 17-01-023), SCE's Alberhill Substation Project (A.09-09-022), and SCE's Mira Loma-Jefferson Line Project (A.15-12-007). These are "Post-Application Projects." No projects were identified in the 2019 GNA/DDOR filings that are expected to undergo review pursuant to GO 131-D in the future.

needs. In addition, says SEIA, a consistent 10-year planning assumption should be used across proceedings for projects that involve transmission investments that have a longer 10-year planning horizon.

SEIA also recognizes the dynamic nature of grid needs and acknowledges the difficulty of forecasting them over a 10-year period. SEIA supports focusing DIDF on the 5-year planning horizon in which there is greater certainty of the needed projects. This also means that there is a strong need to develop long-term estimates of unspecified avoided transmission and distribution costs to cover future years after the 5-year forecast period, an issue that is now before the Commission in both R.14-08-013 and R.14-10-003.

PG&E states that since it does not have any non-California Independent System Operator (CAISO)-jurisdictional transmission and sub-transmission components, PG&E does not include any in the GNA. PG&E included the distribution component of Estrella Substation, whose in-service date would occur outside the 5-year window, in its 2019 GNA/DDOR.

SDG&E's states that it could have a transmission project with a distribution component subject to the DIDF, but like PG&E, believes that the Pre-Application Projects should be evaluated in a single proceeding. SDG&E prefers that is be evaluated in the GO 131-D proceeding rather than the DIDF. SDG&E adds that extending the distribution planning horizon from the current 5-years to 10-years would change the distribution projects that are reported in SDG&E's GNA/DDOR. As nearly all distribution needs can be identified and addressed within a 5-year period, there is little advantage in making commitments now for needs that may arise after year five.

Public Advocates states that it is unclear how it would be possible to compare different projects with different planning assumptions (*i.e.*, transmission and sub-transmission projects as compared to distribution projects). There is an inherent difference in the timeline requirements for transmission/sub-transmission projects and distribution projects. Distribution needs are smaller in scope, and potential solutions often need to be developed on a shorter timeline to meet those needs. Public Advocates notes the Commission should clarify whether it wants the DIDF process to continue to focus on deferring distribution projects or, instead, shift the focus to identifying deferral of transmission and sub-transmission sized projects.

SCE agrees with Public Advocates that a 10-year planning assumption and forecast should not apply to the identification of all transmission and sub-transmission GNA components. As with any forecast, the longer the horizon extends, the more uncertainty is introduced in the accuracy of the forecast values for years further out. SCE claims that minimal value to DIDF stakeholders would be realized from increasing the planning horizon for distribution projects to 10-years because of the inherent forecast uncertainty after the fifth year. SCE acknowledges that projects subject to GO 131-D have longer, 10-year planning horizons.

3.3.2. Discussion

The IOUs are working towards achieving common, comparable GNA/DDOR filing datasets (*i.e.*, standardizing filing data and documentation across the IOUs), but more work is still needed. The IOUs should use the same IEPR datasets to prepare their GNA/DDORs. To ensure this occurs, the IOUs should meet and confer to establish which IEPR datasets to use for disaggregation and forecasting in 2020 and present the selected datasets to Energy Division for approval in coordination with the IPE (Reform No. 3). The datasets should each be identified in the IPE Plan. IEPR datasets should be used where feasible for disaggregation, but if other datasets must be used, the IOUs should explain why and seek Energy Division approval before deviating from the practices employed by the other IOUs or from reliance on IEPR datasets.

This *Ruling* restates that the IOUs should provide forecast facility loading data for all feeders in their distribution system in compliance with the *May 7, 2019 Ruling*. This data continues to be useful for effective stakeholder participation and analyses of DIDF outcomes. The *May 7, 2019 Ruling* further states, at A1, that circuit-level planning assumptions and GNA digital datasets should include a unique row for distribution circuits and substation transformer banks and include all circuits rather than just circuits with deficiencies. The IOUs should continue to provide forecast loading data for all feeders, not just feeders with deficiencies and be careful to follow the GNA/DDOR requirements specified in Appendix A to the *May 7, 2019 Ruling* (Reform No. 13).

This *Ruling* agrees with GPI that SCE and SDG&E should provide tabulated summary tables showing the types and numbers of grid needs, planned investments, and candidate deferrals identified each cycle similar to the ones PG&E provided (*see* PG&E GNA 2019 at 15-18 and PG&E DDOR 2019 at 7-10) to allow for a comparison to filings from prior years and among the IOUs (Reform No. 4).

As the IPE indicated, the IOUs should calculate LNBA values for both planned investments and candidate deferrals based on the assumption that deferral would extend to the end of the 10-year planning period. The two LNBA values should align, which was the intended meaning of IPE Recommendation C in the *May 7, 2019 Ruling*. If an IOU has not identified a project need (*i.e.*, peak MW shortfall) for the entire planning period, they should use the largest forecast need identified (*i.e.,* peak MW shortfall for year 5). If the IOUs prefer to use

LNBA ranges for the planned investment lists, then the ranges should be tighter than those provided by SCE and SDG&E in 2019. Energy Division should either approve the use of ranges proposed by the IOUs prior to implementation or determine if ranges should not be used (Reform No. 5).

The IOUs should continue to provide customer composition details for planned investments. Stakeholders should comment further on the value of this data in their recommendations for DIDF reforms.

As the IPE stated, the GNA/DDOR filings should provide further information regarding DER-driven needs, *e.g.*, the required equipment and steps taken by the IOU to develop the non-DER solution as well as the steps planned or taken by the IOU to upgrade monitoring and control systems to allow DERs to meet such needs in the future (Reform No. 6).

3.3.2.1. Discussion Specific to Pre-Application Project Planning Horizons

Pre-Application Projects are addressed in Section 5.6, but the GNA planning horizon for these types of projects is discussed here.

This *Ruling* agrees with parties that a 5-year planning horizon makes sense for distribution needs identified in the GNA, but a 10-year planning horizon makes sense for larger transmission and sub-transmission projects, *e.g.*, Pre-Application Projects pursuant to GO 131-D. The GNA should apply a 10-year planning horizon for Pre-Application Projects but continue to apply a 5-year planning horizon for all other projects (Reform No. 7). This change may result in the inclusion of more Pre-Application Projects in the GNA and DDOR filings. Stakeholders should continue to evaluate the inclusion of Pre-Application Projects in the DIDF and provide recommendations for potential reforms for future DIDF cycles. (Additional discussion on this topic can be found in Section 5.2, Forecast Certainty Metric and Qualitative Assumptions, and Section 5.6, Pre-Application Projects.)

3.4. Confidentiality

This section addresses items 2 and IPE S from the *November 8, 2019 Ruling* (*see* Attachment B to this *Ruling*).

3.4.1. Party Comments

Public Advocates has received all confidential data. It had no other comment. SEIA states that SDG&E's data was heavily redacted which made it difficult to recreate the cost-effectiveness analysis for individual projects. Although this issue has been reduced in recent filings, CESA recommends that the Commission establish a policy that broad categories of data not be made confidential unless the IOUs make such requests and demonstrate the need for confidential treatment on case-by-case basis. CESA states that data should only be treated as confidential where clearly applicable under current Commission rules or where the Commission has made a categorical policy or case-by-case determination that the data are confidential.

PG&E states that it applies confidentiality standards to customer data in compliance with the Commission's and California's privacy rules, including the 15/15 rule requiring aggregation of customer datasets and the new requirements of the California Consumer Privacy Act, effective January 1, 2020. PG&E also applies confidentiality to data that is subject to other confidentiality requirements, such as cyber security sensitive data, physical security sensitive data, market sensitive data, non-public material financial data, trade secrets and intellectual property. In all such examples, PG&E says that it follows the guidance of the Commission, including guidance regarding processes for participant access to such confidential data, such as through non-disclosure agreements or filings consistent with the Commission's GO 66-D. Comments from SCE and SDG&E align with those of PG&E.

3.4.2. Discussion

This *Ruling* requires that if any party wishes to redact IEPR data (including IOU data), the party proposing the redactions must follow the requirements that have been established previously in this proceeding, *i.e.*, that the party claiming confidentiality file a motion with a supporting declaration that provides the necessary granularity as to the information proposed to be redacted, and the legal justification for each redaction category.

The Excel prioritization metrics and LNBA calculations workbooks described in Section 5, Prioritization Metrics, should be provided in a fully unlocked and functional format with all formulas in place and operable. To the extent fully operable Prioritization Metric Workbooks with all LNBA data included cannot be made public, a complete PDF of all worksheets with the necessary redactions made shall be filed in addition to Excel workbooks (Reform No. 22).

3.5. DRP Data Portals (Online Maps)

This section addresses Item 3 from the *November 8, 2019 Ruling* (*see* Attachment B to this *Ruling*).

3.5.1. Party Comments

The parties agree that all planned investments should be shown on the maps and included in the data presented on the DRP Data Portals. Public Advocates also says that planned transmission investments, approved by the Commission, could be shown in a separate map layer. These showings would help all stakeholders have a better understanding of where grid needs exist and allow developers to consider where they might be able to locate DER alternatives relative to the planned investments.

SCE states that it is exploring the way it displays new substations to report as needs on existing assets (*e.g.*, Valley 500/115-kV Substation and proposed Alberhill 500/115-kV Substation). SDG&E states that all planned investments and candidate deferral projects identified in SDGE's DDOR that do not violate the 15/15 customer confidentiality rule are shown on their DRP online maps.

GPI comments that the connection between ICA data and DIDF should be enhanced. GPI believes that enabling the ICA to inform customer choice DER programs will encourage and leverage DER services that bolster the distribution grid, and perhaps even meet or defer planned investments to distribution needs identified in the GNA.

3.5.2. Discussion

The parties are unanimous that all planned investments and deferral opportunities should be shown on the maps and included in the data presented on the DRP Data Portals (Reform No. 8). S CE says that is it already making improvements. The *Ruling* clarifies here that GO 131-D permitting projects should be reflected on the DRP Data Portals just like any other planned investment or deferral opportunity (*see* also Section 5, Pre-Application Projects). In addition, the *Ruling* agrees with Public Advocates that the location of approved transmission projects should be shown on the online maps to support DER planning. SCE already provides some of this information in public reports to local jurisdictions and on their DRP Data Portals, for example. It would be helpful if this type of information was provided on the IOU's web-based DRP Data Portal maps (*e.g.*, the IOU's transmission and distribution circuits and reliability (System Average Interruption Duration Index [SAIDI]/System

Average Interruption Frequency Index [SAIFI]) histories for those circuits as well as planned transmission and distribution investments).[7] SAIDI and SAIFI data are used to determine the effectiveness of planned reliability upgrades[8] (Reform No. 9).

This *Ruling* also agrees with GPI that the connection between ICA and GNA data sets should be explored. For example, it may be beneficial for a version of the ICA data layer to display added loads from forecast growth identified in the GNA. This would provide more transparency to customer DER siting opportunities. Energy Division should continue to explore the ICA-DIDF relationship, and parties are encouraged to discuss possible reforms in the 2020-2021 DIDF cycle to enhance the relationship and overall DRP Data Portal utility. The addition of fire-threat data layers to the DRP Data Portals is discussed in the following section.

3.6. Grid Needs and Deferral Screens

This section addresses items 4, 7, 13, 26, IPE A, IPE B, IPE E, and IOU d from the *November 8, 2019 Ruling* (*see* Attachment B to this *Ruling*).

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[7] "SCE provides all its local and tribal governments with annual reports containing information on the distribution circuits and reliability (SAIDI/SAIFI) histories for those circuits serving their jurisdiction, as well as SCE's planned transmission and distribution investments in their jurisdiction for the upcoming year," at 2, April 7, 2020 *SCE Response to Alice Stebbins, Executive Director, CPUC,* regarding March 17, 2020 request to implement expected Microgrid and Resiliency Strategies Rulemaking (R.19-09-009) directives. SCE continues in the letter, stating, "In light of COVID-19, SCE is evaluating how best to present information and may need to do so virtually in the near future. All reports are made publicly available on SCE's website (http://www.on.sce.com/reliabilityreports), while distribution and transmission infrastructure information is also publicly available via SCE's Distributed Resources Plan External Portal (https://ltmdrpep.sce.com/drpep/).

[8] Measures of electric grid reliability standardized by the Institute of Electrical and Electronic Engineers. The Customer Average Interruption Duration Index (CAIDI) is calculated by dividing SAIDI by SAIFI. CAIDI provides the average time to restore power after an outage.

3.6.1. Party Comments

Public Advocates states that reliability and resiliency needs should be discussed separately. Parties should also be enabled to consider reliability and resiliency needs separate from other needs, such as capacity, says Public Advocates. CESA and SEIA agree. CESA believes that reliability and resiliency are unique and subject to different planning standards and/or performance requirements. CESA notes that the IOUs have been encouraged to bifurcate and separately define the performance requirements for capacity needs versus reliability needs. Resiliency needs should be defined and specified as a separate product, says CESA.

CESA acknowledges that traditional, wires-based planned investments can address multiple grid needs at once, but bundling the service requirements can makes it challenging for stakeholders to differentiate the distribution grid needs (*e.g.*, capacity versus reliability versus resiliency) as well as foreclose on innovative possibilities for portfolios of DER solutions to address specific needs (*e.g.*, whereas some DERs can better address capacity needs, others could be positioned to address resiliency needs). Even if a single DER project or counterparty can address the multiple grid needs, separate definition and specification of the different needs supports the development of innovative solutions that may leverage the multiple-use application rules.[9]

PG&E and SDG&E agree that reliability and resiliency grid needs should be listed separately. PG&E argues, however, that all needs must still be met to successfully defer a planned investment. SDG&E adds that while grid needs are already shown separately in their GNA/DDOR, the needs should not be

[9] Appendix A to D.18-01-003 at 1.

separated for deferral opportunities. SCE agrees with PG&E and SDG&E that planned investments cannot be deferred unless all the associated grid needs are met; thus separating project needs for deferral opportunities would result in different, and most likely multiple, less cost effective, and inefficient solutions. PG&E notes that as part of its regular application of lessons learned, it plans to revisit the classification of grid needs in its 2020 GNA. Specifically, some needs listed as reliability in its 2019 GNA (*i.e.*, those that required islanding operation) may be classified as resiliency needs.

CESA's reply states concerns about separating out the various grid needs of a planned investment are misplaced. CESA agrees that the entire planned investment should be deferrable but adds that the DER community should be enabled to separate out the needs so that various portfolio-based solutions could be pursued. While any single DER resource may only address one need, says CESA, the collection of DERs procured and contracted as a portfolio can address the multitude of needs. While this could increase complexity, complexity is not a sufficient reason to not pursue DER alternatives if more cost-effective outcomes can be achieved through deferral.

CESA believes that improving on definition of resiliency grid needs is important to guiding the DIDF process and its ability to address resiliency-focused traditional infrastructure projects. Public Advocates agrees and states that defining more comprehensive reliability and resiliency needs should be a priority, but recommends that definitions be adopted in the microgrids and resiliency proceeding.[10] CUE also agrees that the definitions of

[10] *See* R.19-09-009, *Order Instituting Rulemaking Regarding Microgrids Pursuant to Senate Bill 1339 and Resiliency Strategies.*

reliability and resiliency needs should be refined and points to PG&E's clarifying definitions in their 2019 GNA report at 9 and 18.

CUE further comments, however, that developing incremental solutions to each unique grid need would complicate the DIDF process. For example, if a planned investment had capacity, reliability, and resiliency value, separating the values into three different solutions could mean different distribution projects to address each of the solutions such that a comparison against DERs could be made. The number of possible combinations would result in a confusing selection process and excess work for the utility in designing alternatives to wired solutions. Separating out resiliency and reliability components would be impractical, concludes CUE. SCE provides comments that align with those from CUE presented in this paragraph.

SEIA adds that increased concerns about wildfires and Public Safety Power Shutoffs (PSPS) events support arguments that resiliency should be accounted for in the planning process separately from reliability. SEIA cites to studies that refer to reliability as the ability of an electric system to maintain service in the face of normal challenges to continuous operations. Resiliency, says SEIA, emphasizes the ability to respond to and recover from low-frequency, high-consequence events that may last longer and affect larger areas. SEIA is supportive of establishing resilience metrics such that priority can be assigned to investments that increase community resilience.

CESA and SEIA support the identification of a value for lost load and/or resiliency value to be used for the DIDF prioritization metrics, even if only an interim value while the microgrids and resiliency proceeding remains open to address this topic area and resiliency more broadly. A number of parties disagree with SEIA and CESA, however, noting that the microgrids and resiliency proceeding is scoped to address resiliency.

3.6.1.1. Circuit-Segment Level Needs and the Timing Screen

Parties agree that GNA/DDOR data sets should be manageable. Circuit-segment level (line segment) grid needs require extensive power flow analysis and include many underlying assumptions, says SDG&E. Public Advocates states that providing all required data for each line segment could make the GNA/DDOR difficult to review and analyze without providing a comparable benefit. This is particularly true if the timing of line-segment needs, which are only provided 3-years out, automatically results in their exclusion from consideration in the DIDF RFO process.

PG&E supports aligning and simplifying the GNA/DDOR, and the IPE's suggestion to report only segments with needs rather than identifying each segment studied. PG&E plans to only include one grid need for each distribution line segment, rather than listing each node separately, because, according to PG&E, this aligns with the other 2019 IOU filings. GPI agrees that line segments should be retained in the DIDF process with the anticipation that advances in DER implementation and future adjustments to the timing screen will make these grid needs eligible for DER solutions in the future.

SCE supports providing data at the circuit level for circuits showing needs but prefers that the data be limited to the first 3-years of the GNA planning period. This approach is consistent with the ability of SCE's tools to identify line segment, voltage and VAR (volt-ampere reactive/reactive power needs) or Volt/VAR grid needs and projects, which are limited to the first 3-years. As SCE's tools and datasets evolve, they will seek to extend this forecast period.

Public Advocates questions whether SCE provided circuit-level data at the circuit-segment level in their 2019 GNA.

While GPI agrees with parties and the IPE that line-segment needs should be limited to segments for which needs are identified, GPI expressed concern that the timing screen overly restricts planned investments from consideration as deferral candidates. GPI strongly recommends the 3-year timing screen be shortened to the maximum extent possible to allow for more candidate deferral opportunities. Alternately, GPI states that the modeling timeframe for line segments and Volt/VAR needs should be extended beyond 3-years such that longer-term needs identified can be considered for deferral. CESA adds that DER tariffs (once developed) would provide the advantage of incremental procurement over time, thus reducing the lead time required to address distribution needs. Party comments about the timing screen are further summarized in Section 4.1, Proceeding Status.

In addition, CESA states concerns with discrepancies between SDG&E's GNA and DDOR. While certain distribution grid needs were identified in SDG&E's GNA for specific substations or circuits, those needs were not reflected in the DDOR filing at the same substations or circuits. SDG&E's team explained at the 2019 DPAG meetings that this discrepancy was due to those needs being "eliminated" after accounting for load transfers and "modeling discrepancies." The filings should be reviewable by stakeholders as standalone documents, says CESA, without requesting additional information from SDG&E.

3.6.2. Discussion

The consideration of planned investments with a combination of needs (*e.g.*, capacity, reliability, and resiliency) should include an evaluation of how the needs could be segregated in some cases. The IPE reports for PG&E and SCE provided examples.[11] Parties have provided thoughtful comments on this subject, and this *Ruling* agrees with the majority of parties that capacity, reliability, and resiliency grids needs should be identified as separate grid needs.

This *Ruling* further requires that the IOUs enable stakeholders to consider the various grid needs served by planned investments separately. Separating out the need types may lead to innovative DER solutions. Where a planned investment is capable of fully addressing two or more grid needs, there may be one deferral opportunity that addresses all the needs or several deferral opportunities to address the needs. Each opportunity should be ranked (Reform No. 12). As the DIDF process seeks to test innovation and continually improve, parties are encouraged to comment on potential reforms related to this approach for future DIDF cycles.

The majority of parties believe that a value of lost load (*i.e.,* resiliency value) should be the subject of future DIDF reforms in coordination with microgrids and resiliency proceeding outcomes (R.19-09-009). This seems reasonable. This *Ruling* agrees with CUE that PG&E's working definitions of reliability and resiliency provide clarifying value and agree with other parties similarly commenting that the definitions should be refined. Energy Division should continue to explore the definition of grid needs applicable to the DIDF in coordination with other proceedings.

This *Ruling* agrees with SEIA that increased concerns about wildfires and PSPS support arguments that the potential needs for resiliency services, as previously defined in this proceeding, should be accounted for in the distribution planning process. To help achieve that goal, IOUs should include

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[11] *Independent Professional Engineer SCE 2019 GNA/DDOR Report*, November 5, 2019, at 24, and *Independent Professional Engineer PG&E 2019 GNA/DDOR Report*, November 5, 2019, at 24

the fire threat and tree mortality data from the online Commission FireMap (https://ia.cpuc.ca.gov/firemap) as layers on the DRP Data Portal online maps (Reform No. 10). This will be useful for customer siting with respect to Self-Generation Incentive Program (SGIP) resiliency incentives,[12] for example, which may also lead to deferrals. Energy Division should explore with the IOUs to what extent and when detailed historical PSPS outage data can be provided and mapped on the DRP Data Portals in coordination with existing efforts, including those in R.19-09-009[13] (Reform No. 11).

The IOUs should continue to perform and document line-segment analyses at the circuit-segment level for the GNA but be allowed to only list line segments for which needs are identified rather than listing all line segments. This should make the filings more manageable to prepare and review (Reform No. 14).

In the future, streamlined procurement options and improved IOU planning processes are expected by SCE and other parties that may allow for a reduction in the time required to procure solutions for line-segment and other near-term needs. The 3-year timing screen was developed early on in the proceeding, and since then, DIDF procurement process has improved. It may be time to re-evaluate the 3-year screen such that projects with needs occurring in less than 3-years are potentially deferrable, *e.g.*, traditional projects to defer that do not have large, lead time infrastructure items (Reform No. 16).

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[12] D.20-01-021

[13] "Starting this year, SCE will also include the previous four years of PSPS outage information for the distribution circuits serving each jurisdiction. The 2020 reports are anticipated to be completed in April and will be made publicly available on SCE's website" at 3, April 7, 2020 *SCE Response to Alice Stebbins, Executive Director, CPUC*, regarding March 17, 2020 request to implement expected Microgrid and Resiliency Strategies Rulemaking (R.19-09-009) directives.

As recommended by the IPE, SDG&E and the other IOUs (if applicable) should provide the reasons for removing needs from their GNA/DDOR filing. SDG&E's list of substation bank and circuit level loading and deficiencies provided in Appendix 2 (Tab "Ruling – Cir-Bank Capacity-Pub" in the Excel workbook) to their GNA/DDOR filing was developed prior to any newly identified phase balancing, transfer of loads or fixing of modeling discrepancies. It was not possible to know which of the bank/circuit level needs identified by the analysis were addressed using the above-mentioned actions without obtaining additional information from SDG&E. This *Ruling* agrees with the IPE that this is an important step in the GNA/DDOR process because it screens out some needs that may otherwise have to be mitigated by installing new equipment. In the interest of transparency and to support the IPE's verification and validation, SDG&E should provide the reasons for removing these grid needs (Reform No. 15).

3.7. Grid Modernization Plans and GRCs

This section addresses items 8 and 31 from the *November 8, 2019 Ruling* (*see* Attachment B to this *Ruling*).

3.7.1. Party Comments

Public Advocates states that the PG&E and SCE Grid Modernization Plans request similar investments in the following areas: 1) engineering and planning software tools; 2) system-wide hardware and software to increase the control and monitoring of the distribution grid; and 3) location specific upgrades to mitigate forecasted DER issues. Systemwide hardware and software is intended to provide grid operators with the ability to better monitor the status of the distribution grid in near-real-time, and either remotely or automatically reconfigure equipment to maintain voltage and power quality and minimize outage frequency and scope of impacts. The related investments include new automation equipment in substations and on circuits, new control equipment in the Distribution Control Centers and communication systems. The drivers for these investments include improved reliability and safety in addition to support for increased DER deployment, which could support the Commission's objectives for DER integration and improved resiliency.

Public Advocates argues, however, that the specific requests by SCE and PG&E are not optimal in terms of timing, scope, and cost, and that they fail to fully leverage third-party equipment including communication systems and control/monitoring equipment required by Rule 21 and via smart inverters. To the degree that these system-wide utility investments could be replaced with third-party owned equipment, they should be included in the DIDF process, says Public Advocates. Location-specific upgrades are for IOU investments on specific circuits and substations where the IOU has forecasted grid needs that are attributed to organic DER growth. These types of projects are the antithesis of DIDF projects in that anticipated DER growth is the purported cause of a grid need rather than provide a solution to grid needs, says Public Advocates. It will be important to consider how Rule 21 telemetry systems and smart inverters could be used to mitigate forecast DER impacts, either through changes to the Commission's requirements, or through third-party programs.

SCE states that the GNA/DDOR filings serve a separate purpose compared to Grid Modernization Plans. The GNA/DDORs document the disaggregated IEPR forecast for all circuits in an IOU service territory, needs that result from that forecast, the traditional wires projects that solve those needs, and a set of wires solutions that could potentially be deferred by DERs. Grid Modernization Plans identify the software and field technologies required to facilitate the integration of DER into distribution and sub-transmission planning and operations, says SCE. Hence, the GNA/DDOR and DIDF process identify the opportunities for DER to obtain added benefits of deferring a wires solution, while Grid Modernization advances planning and operational software tools paired with field sensing and automation to utilize those DERs to solve grid needs and maximize benefits, explains SCE.

Public Advocates and CESA state that unique Project IDs in the GNA/DDORs should link to items included in the IOU GRCs because it will allow developers, IOUs, and regulators to track costs as they develop over time. Public Advocates agrees that it should be assumed that GRCs will include additional investments that do not have a GNA/DDOR Project ID because some types of equipment cannot be deferred by DERs. GPI supports using a unique GNA ID that helps align grid needs identified in the GNA with planned investments and candidate deferral opportunities in the DDOR filings.

SEIA supports a system that clearly links planned investments in the GNA/DDOR to items included in IOU GRCs. GNA/DDOR projects account for a fraction of the distribution investments for which the IOUs seek rate recovery in the GRCs, says SEIA.

SCE includes unique IDs that link to applicable items in their GRC, but states that not all items in the GNA/DDOR can be linked to a specific item in the GRC. For example, says SCE, some capital programs in the GRC use trend-based analyses to forecast test-year expenditures, since the exact system need is likely to change but the magnitude of system need is historically proven to exist. SCE identifies several categories of equipment requested in GRCs that cannot be deferred by DERs.

PG&E supports the provision of project IDs in the GNA/DDOR for ease of use of the reports, but states that the IDs should not be required to link directly to GRCs. PG&E explains that unless the GNA/DDOR are published during the IOU's GRC year, it will be difficult to make a complete match to the project list included in the GRC, which occurs tri-annually. PG&E adds that projects that include the addition of Supervisory Control and Data Acquisition equipment are included in PG&E's DDOR but are screened out due to the 3-year timing screen.

SDG&E's reports provide a unique ID for each grid need and planned investment, but at this time, SDG&E says they have not determined whether or how these IDs will be used their GRC. SDG&E notes that there may not be a one-to-one correspondence between planned investments in SDG&E's DDOR and distribution expenditures included in SDG&E's GRC. SDG&E believes that the GRC should identify requested dollars for forecasted aggregated distribution projects, for which SDG&E would have flexibility in determining how, where, and when to expend those dollars for maximum consumer benefit.

3.7.2. Discussion

Public Advocates presents interesting findings from their review of the PG&E and SCE Grid Modernization Plans that should be further explored by Energy Division in consultation with the IPE and DPAG stakeholders. The IOUs should discuss the potential benefits of third-party ownership of equipment including communication systems and control/monitoring equipment required by Rule 21 and associated with smart inverters in their recommendations for DIDF reform (Reform No. 17).

This *Ruling* agrees with the parties that project ID numbers are helpful for processing the GNA/DDOR data. Ideally, planned investments and costs would align with those presented in GRCs, but the IOUs provide reasonable explanations for why this is not always the case. That said, the IOUs should make every effort to ensure that planned investments presented in the GNA/DDORs align with those presented in the GRCs.

SCE's 2019 system of grid need ID numbers (GNA ID), planned investment ID numbers (DDOR Project ID), and ID numbers for each line item in the planned investment list (DDOR ID) appeared to be the most complete.[14] The other IOUs should replicate SCE's approach. The project numbers should be unique and link to items in the IOU GRCs. Where the IOUs require differences in approach, they should explain the difference in comparison to SCE's approach in their 2020 GNA/DDOR filings. In future DIDF filings, the grid need ID and project ID systems should be roughly equivalent and approved for implementation by Energy Division (Reform No. 18).

4. Prioritization Metrics

4.1. Prioritization Metrics Workbooks and Joint Template

This section addresses items 10, 11, and IPE L from the *November 8, 2019 Ruling* (*see* Attachment B to this *Ruling*).

4.1.1. Party Comments

GPI stated that SCE and PG&E provided clear explanations of their approaches for determining the prioritization Tiers, but SCE provided the most unbiased methodology by implementing a semiquantitative normalized ranking system. GPI, Public Advocates, and CESA agree that SCE's metrics should be used as a starting template. CECA noted that the Commission allowed for some differentiation of prioritization metrics to test out different criteria, opting to

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[14] *Amended Reports of Southern California Edison Company (U 338-E) of its 2019 Grid Needs Assessment and 2019 Distribution Deferral Opportunity Report*, August 23, 2019, Distribution Deferral Opportunity Report, at 6 to 7.

"gain experience with different prioritization approaches before prescribing a given methodology for ongoing use."[15] With several DIDF cycles now completed, CESA believes it is reasonable to standardize the prioritization metrics. The means by which some of this information is obtained may be different based on IOU grid operations and architecture, but the underlying metrics for prioritization appear to be common. SEIA, GPI, Public Advocates, and CESA support including the LNBA calculations in a common format with one option being within a uniform prioritization metrics workbook.

The IOUs disagree. PG&E says that forcing the IOUs to develop and use a common spreadsheet would ignore the differences between the IOUs service territories, resulting in inaccurate prioritization metrics and a challenge to making the filing date. SCE states that the IOUs have different system designs and different planning practices, and the exact factors considered in the prioritization are tailored to their own system characteristics with different projects, planning software capabilities, and documentation processes. SCE recognized, however, that there could be opportunities to align on the general concepts of prioritization between the utilities to understand which metrics seem to provide the best identification of deferral projects. SDG&E believes that the existing prioritization approaches should continue to be used until there is evidence that they are not resulting in the best outcomes for consumers. CUE's reply states that forcing PG&E and SDG&E to start over would waste ratepayer money and sacrifice the knowledge gained from the previous DIDF cycles.

[15] D.18-02-004 at 48

4.1.2. Discussion

The IPE noted that SCE transitioned to using more quantitative metrics in their prioritization process for their 2019 GNA/DDOR filing and recommended that each utility follow this approach to add additional transparency and help stakeholders understand the basis for project prioritization in order to provide meaningful feedback. The IPE recommended that the IOUs apply the same prioritization process, as much as possible, and strive to use quantified metrics. Furthermore, the IPE noted that the IOUs should review the detailed recommendations provided by the IPE in their respective 2019 DIDF Reports and work together to consider the recommendations including the use of an LNBA/MWh-day metric. This *Ruling* agrees with the IPE and CESA that after having gone through several DIDF cycles, we are now able to begin standardizing more of the filing documentation and metrics.

By standardizing the prioritization metrics workbook, the DIDF process will be more transparent and the DPAG review process more engaging because it would facilitate stakeholder review.[16] The metrics should be quantitative where possible, and any qualitative components should be explained. The approach taken should be uniform across the utilities, however, it is acknowledged that achieving uniformity takes time.

There is general agreement by Public Advocates, CESA, and GPI that the Excel prioritization metrics workbook used by SCE for the 2019-2020 DIDF cycle should serve as the starting template (*i.e.*, the Joint Prioritization Metrics Workbook Template). The IPE also highlighted the benefits of SCE's approach,

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[16] *See* D.18-02-004, Conclusion of Law No. 5, which states, "It is reasonable to affirm that the main objective of prioritization metrics is to characterize candidate deferral projects in a way that enables the IOUs and the DPAG to identify which projects are most likely to result in successful, cost-effective deferrals that provide needed grid services."

even recommending that the other IOUs adopt SCE's workbooks as templates for the 2020-2021 DIDF cycle. While SCE's prioritization metrics calculations may remain imperfect, there is general agreement among DIDF stakeholders that they are the best example to date of a quantitative approach to ranking the viability of candidate deferral projects. Hence, the IOUs should use a common prioritization metrics calculations spreadsheet template based on SCE's 2019-2020 DIDF cycle workbook (Reform No. 19).

SCE's 2019 LNBA calculations where completed in a single workbook containing three worksheets (General Inputs, Project Inputs, and Backend Results). The IPE recommended that the other IOUs adopt SCE's LNBA calculations workbook as a standard template. It should be straightforward to incorporate it into the larger Prioritization Metrics Workbook. Hence, all LNBA calculations should be included in the same workbook (Reform No. 21).

The IOUs should collaborate such that there is a common understanding of each label and formula used in the 2020 Joint Prioritization Metrics Workbook Template and any embedded guidelines for qualitative data (*e.g.*, the Forecast Certainty table of guidelines described below). While the Project ID numbers and names are expected to vary between the IOUs, the approach to calculating the inputs and formulas applied and majority of labels used should be the same. After collaborating, we direct the IOUs to present the final, 2020 Joint Prioritization Metrics Workbook Template to Energy Division for approval as soon as possible or before June 1, 2020 (Reform No. 20).

Once approved, Energy Division may choose to seek stakeholder comments on further improvements to the template during the 2020 Pre-DPAG period if time allows. Energy Division, in consultation with the IPE and Independent Evaluator (IE) as appropriate, should identify further improvements to the prioritization metrics template, IOU-specific workbooks, or underlying metrics or data as needed and require that each IOU implement them (Reform No. 23).

4.2. Forecast Certainty Metric and Qualitative Assumptions

This section addresses items 12, 14, and IPE M from the *November 8, 2019 Ruling* (*see* Attachment B to this *Ruling*).

4.2.1. Party Comments

While SEIA expresses concern about the application of qualitative metrics in general, CESA supports grid operator concerns as part of the qualitative assessment for prioritizing deferrable opportunities, and GPI offers detailed recommendations for how qualitative assessment should be calculated. SEIA and CESA prefer that metrics be quantified where possible, and GPI strongly prefers quantification. CESA, Public Advocates, and GPI agree with the IPE that application of the Forecast Certainty metric should be clarified by the IOUs. GPI further recommends that only the Likelihood score should be used (as opposed to SCE's additional Year of Need Score), and it should be based on a predefined rubric. GPI also states that SCE should clarify how they are normalizing the Likelihood value. SCE stated that they appreciated the IPE's feedback about Forecast Certainty and will review the metric's design and make the necessary updates.

PG&E refers to qualitative assumptions as judgment based on experience with pilots and engineering knowledge of the area. SDG&E states that aspects of prioritization metrics such as forecast certainty and market assessment could include non-quantifiable considerations, such as ease of land acquisition, topography constraints, and irregular loading patterns and adds that grid operator concerns are also raised in the DER contracting process. S CE states that while it will continue to refine its prioritization metrics every year, there will continue to be a need to incorporate qualitative evaluations to determine appropriate prioritization of candidate deferral projects. PG&E noted that it plans to develop a questionnaire for distribution engineers that it will use in its qualitative assessment of the Forecast Certainty metric in future DIDF cycles. It would include such items as the age and condition of existing equipment at the facility.

In addition, the *November 8, 2019 Ruling* asked whether the need date component of the Forecast Certainty metric should be replaced by the expected operational date. PG&E stated that the operational date should be applied because the Forecast Certainty metric is used to prioritize candidate deferral opportunities for solicitation, and the purpose of the solicitation is to source DERs to defer the operational date of planned investments. PG&E further states that the LNBA calculation used in the Cost Effectiveness metric uses the expected operational date (as does the Cost Effectiveness Cap). CESA says to provide both dates for informational purposes but apply the operational date for Forecast Certainty metric calculations because this date may provide more lead time for DER deferral solutions to be procured and deployed.

SCE, SDG&E, and Public Advocates support use of the need date. SCE explains that the because Forecast Certainty metric measures the Likelihood of a grid need materializing at the forecasted time, the need date should be used. SCE notes that the majority of their distribution and sub-transmission planned investments have their need dates and operating dates aligned. SCE cases with misalignment between these dates are mainly due to construction restrictions, permitting restrictions, or resource restrictions due to a regulatory approval process. For these cases, SCE does not require DER solutions to be ready before SCE can install and implement a solution to mitigate the system need.

4.2.2. Discussion

To improve on SCE's 2019 workbooks, the 2020 Prioritization Metrics Workbooks should be annotated by the IOUs to ensure all headings, labels, and formulas used are described and that each spreadsheet column has a defined heading. Unclear labels should be defined (*e.g.*, normalized duration and normalized capacity needs/circuit by project). Qualitative values that are quantified for use in the workbooks should be described (*e.g.*, likelihood, weighted likelihood, and normalized likelihood). This *Ruling* agrees with GPI that the quantification of qualitative values should be based on scoring rubrics that include explanatory narratives. Qualitative values applied by the IOUs that are determined not to be quantifiable should also be fully described. Where qualitative values that cannot be quantified push a candidate deferral into a lower tier than as calculated by the quantified metrics, the utility must document the adjustment (Reform No. 25).

In particular, per the IPE and GPI, the IOUs should develop a table to guide Forecast Certainty metric application because some of the underlying assumptions (*e.g.*, SCE's project Likelihood component) are too subjective or undefined. PG&E noted that it plans to develop an engineering questionnaire to guide Forecast Certainty metric application, and SCE stated that it will continue to refine its metrics every year. Therefore, the IOUs should include a table of guidelines for the Forecast Certainty metric and include it in the 2020 Joint Prioritization Metrics Workbook Template. The table of guidelines will clarify factors that could delay or accelerate project need and establish Likelihood of Project numerical values. The IOUs shall review the design of the Year of Need and Likelihood components of the metric to ensure one does not inadvertently dominate or override the other component and document the results of this review. It may be that only one or the other assumption should be used (not both), as noted by GPI. The weighting of the two components of the Forecast Certainty metric could have unintended consequences. The IOUs should also describe the appropriateness of any weightings they apply to combine Forecast Certainty metric components (Reform No. 24).

At this time, it is reasonable to require that the need date should be used for Forecast Certainty metric calculations. SCE's 2019 Prioritization Metrics Workbook applied the need date, and SCE's model will be the starting point for the Joint Prioritization Metrics Workbook Template that the IOUs will develop. The expected operational date shall also be identified in the workbooks for informational purposes (Reform No. 24).

4.2.2.1. Discussion Specific to Pre-Application Projects and the Forecast Certainty Metric

Pre-Application Projects are addressed in Section 5.6, but application of the Forecast Certainty metric to these types of projects is discussed here.

For Pre-Application Projects, selection of the need date or operational date is more complex. The Forecast Certainty metric on the whole appears to be of limited value for Pre-Application Projects because the utility cannot address the associated needs with the proposed project until a permit is received, and it is not possible for the utility to predict with certainty the permitting timeframe. The IOUs should include the Forecast Certainty metric data for Pre-Application Projects but not apply the data to the prioritization ranking for these projects (Reform No. 24).

4.3. Consideration of Value Stacking

This section addresses items 15 and IPE H from the *November 8, 2019 Ruling* (*see* Attachment B to this *Ruling*).

4.3.1. Party Comments

CESA states that qualitative prioritization metrics could be developed around other IOU-specific needs and/or system needs that could highlight how DER solutions could stack value or materialize in the competitive solicitation as a cost-effective mitigation measure. CESA believes the IOUs are well-positioned to provide narrative descriptions of additional solicitations and procurement opportunities in other proceedings (*i.e.*, value stacking opportunities) because the IOU procurement teams conduct RFOs for multiple programs and needs and have a broader view of overall grid needs. Areas that IOUs have limited insight into could be discussed by other DPAG stakeholders. Community Choice Aggregators are a good example of a DPAG stakeholder that could provide additional insights about value stacking opportunities for various deferral candidates. SEIA states that resiliency, specifically, should be considered in the value stack for the 2020-2021 DIDF cycle.

SCE, SDG&E, and CUE disagree, stating that value stacking should not be included in the prioritization metrics. SCE says that Resource Adequacy (RA), for example, should not be included in the prioritization metrics since this value depends on varying factors such as positional needs and DER technology type that are independent of planned investment cost. Rather, value stacking should occur during the RFO valuation process. During the RFO process, SCE accounts for all benefits in addition to deferral value that the DER provides including RA, energy, Renewable Energy Credit value, etc. SCE assumes that other potential market revenue that the DER could generate is evaluated by the DER developer.

Similarly, SDG&E states that consumers are best served when the DER provider has the responsibility for value stacking, such as, seeking out and participating in markets (*e.g.,* CAISO energy and ancillary service markets) and solicitations (*e.g.,* distribution deferral, RA), that the DER provider finds compatible with its commercial interests. The IOU should not be placed in the position of attempting to determine, in advance of a solicitation, DER providers' commercial interests. In reply, CUE comments that value stacking should not be a part of either the prioritization process or RFO valuation process. PG&E stated that it already includes the products it is buying in its prioritization metrics and more value stack should not be included.

In reply, CESA agrees with SCE and SDG&E that it is up to the DER provider to actually stack value and monetize multiple revenue streams, but still finds merit in including value stacking opportunities as part of the qualitative assessment in the prioritization process. Rather than taking a siloed procurement approach, they recommend considering how an IOU's other needs could also be addressed in a joint procurement effort. For SCE, where another grid value (*e.g.*, RA) is also being bought as part of the DIDF RFOs, the additional value can be reflected in SCE's net market value evaluation, says CESA.

4.3.2. Discussion

This *Ruling* agrees with the IPE that value stacking has the potential to impact the overall cost effectiveness of DER solutions. Many of the comments received indicate it will be complicated to add value stacking into the Prioritization Metrics Workbooks. Given the need to complete the Joint Prioritization Metrics Workbook Template in time for use in the 2020-2021 DIDF cycle, this *Ruling* declines to require value stacking considerations be applied to the metrics at this time.

However, this *Ruling* agrees with CESA that the IOUs are well-positioned to provide insights into value stacking opportunities, including, among others, RA and participation in wholesale markets for energy, capacity, and ancillary services, such as frequency regulation, voltage support, and reactive power. SCE stated that it accounts for all benefits in addition to deferral value during the RFO process. However, communicating SCE's preliminary accounting of benefits during the DPAG process may spur complementary insights from various stakeholders.

Furthermore, it is important that the IOUs carefully consider the extent to which multiple procurement objectives and/or mandates can be satisfied. Even instances that may result in deferral projects exceeding their cost cap because of the ability to simultaneously satisfy various regulatory procurement objectives by stacking revenue streams should be considered. As stated in Multiple-Use Applications (MUA) Decision D.18-01-003 (at 9), the MUA vision was designed to address the fact that market rules (*i.e.,* utility standard contracts and program tariffs) did not support the ability of energy resources to access incremental value and revenue streams. As a result, energy storage, specifically, could not realize its full economic value to the electricity system. As further explained in Appendix B to the decision, the MUA vision is, "to enable energy storage systems to stack incremental value and revenue streams by delivering multiple services to the wholesale market, distribution grid, transmission system, and customers. Achieving this vision increases the value of storage, and potentially other forms of energy resources, and enhances its economic viability and cost-effectiveness."[17]

The IOUs should provide narratives about expected value stacking opportunities for each candidate deferral in the GNA/DDOR filings and those presented during the DPAG meetings (Reform No. 27). In addition, the IOUs should seek to satisfy multiple procurement objectives (Reform No. 26). To the extent PG&E already included value stacking within its 2019 prioritization metrics, this should be discussed with the other IOUs as they complete their Joint Prioritization Metrics Workbook Template for the 2020-2021 DIDF cycle and shared with the DPAG stakeholders as recommendations for potential future DIDF reform (Reform No. 28).

4.4. LNBA Data

This section addresses items IPE F, IPE G, and IPE I from the *November 8, 2019 Ruling* (*see* Attachment B to this *Ruling*).

4.4.1. Party Comments

CESA agrees with the IPE recommendation for greater transparency regarding key LNBA assumptions such as discount rate, revenue requirement multiplier, inflation assumptions, O&M factor, and book life. CESA states that the data should be treated as confidential only where clearly applicable under current Commission rules or where the Commission has made on a categorical or case-by-case basis that the data are confidential. They claim that utilities should not be make unilateral determinations that data are confidential particularly as this proceeding, which has had numerous instances where the utilities

[17] D.18-01-003, January 17, 2018. *Decision on Multiple-Use Application Issues*. Appendix B: Revised Joint Framework, MUA for Energy Storage, CPUC Rulemaking 15-03-011 and CAISO ESDER 2 Stakeholder Initiative, August 7, 2017, at 1.

previously claimed that expansive amounts of data are confidential due to it being "commercially sensitive" or of "security concern."

The IOUs do not oppose providing this data. SCE states that most of the key LNBA assumptions listed by the IPE are used in their cost-effectiveness cap calculation, and that the data are market sensitive. SDG&E stated its concern that sharing detailed cost information data could invite manipulation or adversely affect contractor offers and therefore ratepayer costs and affordability. They note that providing confidential formulas and calculations to stakeholders and potential bidders, even with nondisclosure agreements in place, may compromise the integrity of bids. This data could be used to discern cost caps, potentially leading to bids that are clustered close to cap. SDG&E also stated that the costing data might be used in connection with other utility projects outside the DIDF. PG&E stated its intention to follow the guidance of the Commission, including guidance regarding processes for participant access to such confidential data, such as through non-disclosure agreements or filings consistent with the Commission's GO 66-D.

CESA's reply disputes SDG&E's contention that redactions include specific project costs for planned investments and LNBA variables, because if made public, the data could result in bids clustered just below the cost cap. They cite to the *July 24, 2018 Ruling* for this proceeding that describes how market-sensitive data does not fit within the definition of "trade secrets" and how the Commission already ordered in Decision D.18-02-004 that actual cost of distribution system upgrades be considered public information as part of the ongoing DIDF.

4.4.2. Discussion

This *Ruling* agrees with the IPE that the underlying LNBA data should be provided, including discount rate, revenue requirement multiplier, inflation assumptions, O&M factor, and book life. These and any other key assumptions should be made transparent in the Prioritization Metrics Workbooks filed by the IOUs for the 2020-2021 DIDF cycle. The IOUs should tabulate all assumptions they used in the LNBA model, as well as provide the sources/basis behind these assumptions in all future GNA/DDOR reports (Reform No. 29).

Per the IPE recommendation, the IOUs shall also include, for informational purposes, the LNBA/MWh-day value for each candidate deferral project in the Prioritization Metrics Workbooks. SCE's 2019 Prioritization Metrics Workbook applied the LNBA/MWh-year value. At this time, no change to SCE's LNBA/MWh-year value approach is required other than to also provide the LNBA/MWh-day values for comparative purposes (Reform No. 30).

4.5. Cost Effectiveness Metric and Project Cost

This section addresses items 19, 20, IPE J, and IPE K from the *November 8, 2019 Ruling* (*see* Attachment B to this *Ruling*).

4.5.1. Party Comments

SDG&E agrees with the IPE Recommendation regarding the Cost Effectiveness metric acting as the first threshold metric. SDG&E states that only the least-cost offer is accepted in the DIDF, and only if that offer is cost-effective and conforming in comparison to the conventional infrastructure that SDG&E would defer. GPI generally supports the IPE recommendation as well, but GPI adds that the Cost Effectiveness metric should be calibrated to a set baseline/absolute threshold value because rankings should not be determined relative to the spread of candidate deferral projects for a single year. GPI's reply reiterates that the Cost Effectiveness metric, if used as a threshold metric, must be adjusted to a standardized threshold applicable to all IOUs.

All parties indicate that the planned investment cost identified in GNA/DDOR filings should be based on the latest, most accurate information at the time of consideration in the DIDF process. Parties also indicate that the cost provided should include all deferrable costs. To the extent regulatory and permitting costs are deferrable, they should be included. PG&E adds that to the extent regulatory and permitting costs are not deferrable, for example if they have already been spent, they should not be included. CUE and SDG&E agree with PG&E.

PG&E recommends that detailed information about regulatory and permitting costs for individual projects should be provided as requested by the IPE or party data requests, rather that introducing new filing requirement for all planned investments. SDG&E's comments align with PG&E's. Similarly, Public Advocates states that regulatory and permitting costs should be separately identified by the IOUs to better understand the total cost of a traditional project and better explain the true cost deferral.

PG&E notes that pursuant to GO 131-D, the IOUs are not required to obtain Commission or local discretionary permits[18] to construct distribution projects, except those that may be considered a substation. Thus, permitting and regulatory costs are generally incurred by utilities only when seeking a license via application pursuant to GO 131-D for a transmission-level (*i.e.*, greater than

[18] A discretionary permit requires a decision-making body to exercise judgment prior to approval, conditional approval, or denial. By comparison, ministerial permits are granted based merely on a determination of compliance with applicable statues, ordinances, regulations, or conditions of approval.

50 kV) project. PG&E says that where a licensing project has both transmission and distribution components, professional judgment must be used by the IOU to determine what percentage should be attributed to the distribution component. PG&E states that the majority of their planned investments in the GNA/DDOR to date do not have significant regulatory and permitting costs.

SCE agrees with the other parties about project costs to present in the GNA/DDOR, but notes that D.18-02-004, Ordering Paragraph 2h. requires that, "the information each IOU presents in its GRC testimony shall be consistent with that which the IOU presents in that year's GNA and DDOR reports, while affirming the IOU's ability to update any aspect of its GRC testimony due to emergent needs or changing forecasts that arise following that year's GNA and DDOR filings. The IOUs must explain any discrepancies between the GNA and DDOR reports and GRC testimony within the GRC testimony." SEIA states that there needs to be consistency in cost data between proceedings.

4.5.2. Discussion

The IPE's recommendation that the Cost Effectiveness metric should be given due consideration in the overall prioritization process as a threshold metric is insightful, but this *Ruling* does not require a change at this time given the anticipated work required for the IOUs to prepare the 2020 Joint Prioritization Metrics Workbook Template and then implement it for the August 2020 filings. Instead, the IOUs should describe in their GNA/DDOR documents how they consider the importance of the Cost Effectiveness metric in developing their overall prioritization ranking methodology and discuss the potential for 2021-2022 DIDF cycle reforms related to the IPE's recommendation (Reform No. 31).

Similarly, GPI commented extensively on the current prioritization approach used in the DIDF including recommendations that the prioritization be changed from the current relative ranking among the candidate deferral projects identified each year to a ranking based on a baseline/absolute threshold value for each of the three metrics or a threshold value for a combined project score from the three metrics that would carry over each year. In this way, deferral opportunities would be ranked and compared across years rather than relative to the more limited pool of candidate projects filed in a single year. This idea may have value but making such changes for the 2020-2021 DIDF cycle would likely require substantial work by the IOUs including the development of the necessary numerical thresholds. Instead, the IOUs should consider GPI's comments in their recommendations for potential 2021-2022 DIDF cycle reforms (Reform No. 32).

This *Ruling* agrees with the parties that the cost of planned investments and deferral opportunities reported in the GNA/DDOR and applied to prioritization calculations should include all deferable (unspent) costs, including regulatory and permitting costs. The cost should reflect the total project cost based on the latest, most accurate information at the time of filing. Upon request, the IOUs should itemize regulatory, permitting, or other costs that are already spent or otherwise not deferable (Reform No. 33). This *Ruling* agrees with PG&E and SCE that this need not be added to the list of GNA/DDOR filing requirements at this time.

As stated in D.18-02-004, Ordering Paragraph 2h, the information each IOU presents in its GRC testimony shall be consistent with that which the IOU presents in that year's GNA and DDOR reports. However, Ordering Paragraph 2h also indicates that there may be reasons for discrepancy, and in those cases, the discrepancy must be explained. Any discrepancies should be explained in the GRC and DIDF filings. For the GNA/DDOR filings, however, this *Ruling* agrees with parties that planned investment costs should be based on the most accurate information at the time of filing. If this differs from the GRC, then the IOU should identify the GRC-specific cost and explain the discrepancy but use the latest, most accurate cost data for GNA/DDOR preparation (Reform No. 34).

4.6. Pre-Application Projects

This section addresses items 17, 18, 30, 32 and IPE O and IOU g from the *November 8, 2019 Ruling* (*see* Attachment B to this *Ruling*).

4.6.1. Party Comments

CESA states that the DIDF is a good fit for identifying DER alternative portfolios to Pre-Application Projects because the DPAG involves actual DER providers that can provide insights into assessing the viability of project deferral. CESA believes that such industry insight and expertise may be missing in the application process for these licensing projects because of the resource intensity of participating in each, individual GO 131-D proceeding. SEIA agrees with CESA and further agrees with the IPE that DPAG stakeholders would benefit from additional information about the three Pre-Application Projects identified in the 2019-2020 DIDF cycle.

At minimum, CESA supports the inclusion of Pre-Application Projects in the GNA/DDOR filings as well as their prioritization into the tier structure for informational purposes. Still, CESA believes it may be worthwhile to include deeper discussions on whether and how Pre-Application Projects should be considered in the DIDF process. Considering the high dollar value and long lead time of these projects, CESA believes that there is tremendous opportunity for DERs to serve as a cost-effective alternative.

CESA does not see a need for a Tier 4 option. It should be sufficient to rank Pre-Application Project in the normal three-tier structure and consider whether these projects, such as for the PG&E Estrella substation and 70-kV powerline project (PG&E Estrella Project), could be broken into smaller, deferrable projects. These projects should be treated and assessed like any other planned investment in the DIDF process. To the degree that specific needs can be segregated, CESA believes that such components of projects could be deferred and avoid the need for extensive review under GO 131-D. For the PG&E Estrella Project, CESA observed that only the reliability need was not deferrable, and if the other needs could be addressed through DER solutions, such projects could reasonably be considered for an RFO as part of the DIDF process.

Public Advocates states that the DIDF process might be a useful way for IOUs to analyze potential alternatives to Pre-Application Projects but believes this is generally outside the scope of the DIDF. Public Advocates posits that GO 131-D would need to be amended for Pre-Application Projects to be included in the DIDF. Public Advocates believes that the need for traditional infrastructure projects expected to require GO 131-D permitting must be established through an appropriate regulatory process before consideration in the DIDF. Since Public Advocates recommends not including Pre-Application Projects in the DIDF, they also stated that Tier 4 would not be needed going forward. Public Advocates states that DER alternatives should be presented within each GO 131-D proceeding.

PG&E states that as a general principle, the determination of whether a project or project component can be addressed by DERs should be addressed in only one proceeding. If a distribution component of a Pre-Application Project is evaluated in the DIDF proceeding, says PG&E, the determination of whether such component is appropriately addressed by DERs should be final and binding as to any other proceeding in which the distribution component may also be presented.

PG&E clarifies that a distribution component identified in the DIDF proceeding as appropriately addressed with DERs (*i.e.*, designated Tier 1) should not be subjected to an alternatives analysis during the CEQA review pursuant to GO 131-D or administrative review in the licensing proceeding. Similarly, says PG&E, a distribution component that is identified in the DIDF proceeding as not appropriate for DERs (*i.e.*, designated as Tier 3) may be subjected to an alternatives analysis during the CEQA review in the licensing proceeding, but DERs should not be considered in the alternatives analysis. If a license application is filed for a project with a distribution component that has not been analyzed in the DIDF proceeding or was designated as Tier 2, the distribution component should be analyzed solely in the licensing proceeding from that point forward.

PG&E believes that continuing to review distribution components in the DIDF without establishing a policy such as the one they presented would create uncertainty for the licensing proceeding by introducing the possibility that all or some aspects of the distribution components could be different than proposed in the license application and/or could be undertaken by an unknown third party at some point before the licensing proceeding is complete. This creates the possibility of an unstable, shifting project description that is difficult to analyze in the CEQA process and is difficult to plan and design for from the utility perspective. In reply, PG&E adds that it is not appropriate to plan a deferral for a traditional infrastructure project if the need for the traditional infrastructure project has not yet been established and approved through the appropriate regulatory process.

SDG&E states that where it's distribution facilities are involved in a "connected action" with transmission facilities subject to GO 131-D, such as a planned substation that includes distribution facilities, it is possible that SDG&E could have a Pre-Application Project at the distribution level. In such event, the analysis of non-wires (DER) alternatives should take place within the Pre-Application process, rather than the DIDF, says SDG&E. This would allow for a complete alternatives analysis, potentially mitigating the need identified by Pre-Application Projects, and reducing the submittal of license applications. Pre-Application Projects are currently studied to identify project alternatives prior to the application filing. This is required for all projects pursuant to GO 131-D by CEQA, say SDG&E and SCE.[19]

SCE agrees with SDG&E and proposes to build upon the alternative analysis within the CEQA and GO 131-D process by consulting the market for additional DER deferral opportunities prior to filing the GO 131-D application. The IOUs should continue to include relevant planning data on Pre-Application Projects in their respective GNA/DDOR filings within the first 5-years of the annual planning forecast to provide transparency to stakeholders, says SCE. SCE states that it is valuable to include all projects and relevant data within the annual GNA/DDOR for transparency purposes, but Pre-Application Projects

[19] It should be clarified, however, that alternatives are only evaluated by Energy Division under CEQA and GO 131-D when an Environmental Impact Report is prepared. An alternatives analysis typically does not occur when other types of CEQA document are prepared, such as, Negative Declarations. Energy Division's CEQA Unit often prepares Negative Declarations, and in these cases, DER alternatives are not typically considered in the CEQA process or GO 131-D proceeding.

should not be ranked into the tiers considered for deferral within the DIDF. SCE claims that taking action on a Pre-Application Project via a DIDF solicitation by, for example, awarding a solution prior to analysis within CEQA or the licensing application process, would bifurcate an alternatives analysis into DER and non-DER alternatives and allow such action to take place prior to a full alternatives analysis, potentially in conflict with the GO 131-D and CEQA processes.

The IOUs support the use of Tier 4 for Pre-Application Projects. Tier 4 was created for projects that will not be considered for competitive solicitation within the DIDF, says SCE. F or example, says PG&E, its 2018 DDOR filing included the Llagas Planned Investment as Tier 4 because DER deferment had already been considered elsewhere for Llagas. Likewise, to the extent an alternative analysis for the PG&E Estrella Project is completed in the GO 131-D process, it would be listed as Tier 4 in PG&E's GNA/DDOR filings. PG&E also says that the vast majority of its planned investments listed the GNA/DDOR do not involve GO 131-D.

4.6.2. Discussion

This Ruling clarifies that the inclusion of distribution and sub-transmission components of Pre-Application Projects (*i.e.,* CPUC jurisdictional components) is required in the DIDF (Reform No. 35). SCE proposed in Appendix E to their 2019 GNA (at 1) an SCE-led analysis of alternatives in which they would "consult the market" and consider third-party and IOU owned DERs prior to GO 131-D application filing. SCE proposed to continue including GO 131-D projects in its DDOR for information and awareness. However, SCE did not identify a sufficient forum for stakeholder evaluation of this process or mechanisms for ongoing Commission oversight in advance of application filing that would facilitate modifications to SCE's alternatives analysis and outreach when appropriate. This Ruling establishes that DIDF is the evaluation forum to determine deferral opportunities for CPUC jurisdictional components of Pre-Application Projects.

This *Ruling* agrees with the IPE and SEIA that additional information about the three Pre-Application Projects identified in the 2019 DIDF cycle would be beneficial. The behind-the-meter (BTM) propensity for adoption study cited in the *November 8, 2019 Ruling* for the PG&E Estrella Project is now available.[20] The study discusses PG&E's 2024 Estrella Project ($18.5 million) deferral opportunity/planned investment (*see* PG&E Revised, Public, November 15, 2019 DDOR filing at 38 in Appendix B, Candidate Deferral Opportunities). The BTM study concluded that it is potentially feasible to defer the three distribution capacity needs (5.9 MW) of the deferral opportunity/planned investment with a combination of BTM and front-of-the-meter (FTM) DERs. The report states, "BTM resources, in combination with FOM [FTM] resources, have the potential to cost-effectively avoid or defer the distribution components of the Proposed Project." However, "BTM resources would not be able to avoid or defer transmission components of the Proposed Project, even when combined with FOM [FTM] resources" (at 3). This *Ruling* agrees with CESA and SEIA that projects like this one would benefit from developer comments in the DPAG.

Recent developments in the SCE Circle City Substation and Mira Loma-Jefferson 66-kV Sub-transmission Line Project (SCE Circle City and MLJ

[20] *See* https://www.cpuc.ca.gov/environment/info/horizonh2o/estrella/docs/2020-0131%20ESTR_BTM_Adoption_Propensity_ADA5.pdf

Project; $140 million)[21] are also worth noting. Energy Division's CEQA document considered battery storage alternatives to this project and completed a report to refine the amount of storage that would be required.[22] Subsequent to completion of the CEQA document and supplemental FTM storage right-sizing study, SCE updated the proceeding that 66/12-kV Circle City Substation component of the project was no longer required within SCE's ten-year planning window. SCE also stated that the proposed 10.9-mile, 66-kV sub-transmission line component of the project could be addressed by 2.7 miles of 66-kV reconductoring.[23] The remaining reconductoring project might benefit from consideration in the 2020-2021 DIDF cycle.

SCE's 500/115-kV Alberhill Substation Project (SCE Alberhill Project, $464 million)[24] was filed pursuant to GO 131-D in 2009 (A.09-09-022). In D.18-08-026, the proceeding was held open for SCE to make its final case regarding changing load forecasts, system peak demand, and the feasibility of alternatives to the project. SCE provided updates to Energy Division in 2019, and the project

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[21] *See* Final Environmental Impact Report at 5-17 (*Appendix G: Draft EIR as Revised by Final EIR*), December 2018, here, https://www.cpuc.ca.gov/environment/info/esa/Circle_City/index.html

[22] *See Attachment 4 to Administrative Law Judge's Ruling Vacating Previously Established Proceeding Schedule and Directing Further Actions*, June 5, 2019, A.15-12-007. The study is titled, *Draft Energy Division Staff Report. A Battery Storage Right-Sizing Case Study Using an Advanced Geospatial Grid Analytics and Big Data Platform: Supplemental Analysis for the Distribution-Level Battery Storage Alternative to the Proposed Southern California Edison Circle City Substation*, June 2019.

[23] *Southern California Edison Company's (U 338-E) Response to Administrative Law Judge's Ruling Adopting Interim Schedule and Directing Further Activities and Updates,* March 31, 2020, A.15-12-007.

[24] *Concurrence of President Michael Picker on Item 26a on the Commission Voting Meeting Agenda of August 23, 2018, Decision Regarding Application of Southern California Edison Company for a Certificate of Public Convenience and Necessity for the Alberhill System Project,* September 14, 2018, A.09-09-022.

continues to be reviewed by the Commission. Projects like this one would benefit from developer comments in the DPAG.

This *Ruling* agrees with Public Advocates and PG&E that the relationship between the DIDF and GO 131-D is potentially complex, but believes that the proceeding opened for each Pre-Application Project is best suited to determine whether and how the project should be evaluated under DIDF after the application is filed. These, "Post-Application Projects" may benefit from ongoing developer comments in the annual DIDF about the extent to which DERs can defer all or part of the projects. It may also be beneficial to seek offers via RFO for certain project components, *e.g.*, the distribution components of PG&E's Estrella Project or the 2.7 miles of 66-kV reconductoring for SCE's Circle City and MLJ Project. In other cases, the GO 131-D proceeding may determine that ongoing inclusion in the DIDF should continue to be tracked for informational purposes but not lead to annual inclusion in DIDF RFOs. The parties have not yet identified a clear conflict between the DIDF and GO 131-D.

While it remains possible that parts of GO 131-D should be refined to reflect the DIDF or the DIDF refined to reflect GO 131-D, it is not clear at this time what refinements may be needed. If the project uncertainty described by PG&E creates an impediment to CEQA review or roadblocks to IOU project planning, these difficulties should be better described in future DIDF reform comments (Reform No. 38). Where CAISO approval of a project need is required, this *Ruling* agrees with PG&E's reply comment that Pre-Application Projects in the DIDF should already have an established need. It might not make sense (in most cases) to complete an RFO for the distribution component of a CAISO-jurisdictional project that does not yet have a proven transmission need. The IOUs should include information about the approval status of

Pre-Application and Post-Application projects in the GNA/DDOR narrative and DDOR spreadsheets (Reform No. 37).

Overall, this *Ruling* agrees with CESA's reply comments that indicate ongoing review is warranted. At this time, neither Pre-Application Projects nor the three, 2019 Post-Application Project examples from the DIDF should be removed from the DIDF. Stakeholders will benefit from continuing to monitor interactions between the DIDF and GO 131-D. Where parties identify clarifying DIDF modifications with respect to GO 131-D, they should propose them as potential DIDF reforms. Among the topics to explore in future reform recommendations may be identifying thresholds for establishing that Pre-Application Project needs have been approved by the required entity (*e.g.*, CAISO, Commission, and/or internally at IOU) to warrant the solicitation of deferral opportunities for its distribution components. Post-Application Project needs should be address in the GO 131-D proceeding prior to DIDF RFO if determined by the GO 131-D proceeding.

It is important to note that considerations for GO 131-D Permit to Construct (PTC) applications and Certificate of Public Convenience and Necessity (CPCN) applications are typically different. CPCN applications consider need, cost, and non-wires alternatives,[25] but PTC applications typically do not consider need or cost.[26] PTC applications generally consider non-wires

[25] California Public Utilities Code Section 1002.3 states, "In considering an application for a certificate for an electric transmission facility pursuant to Section 1001, the commission shall consider cost-effective alternatives to transmission facilities that meet the need for an efficient, reliable, and affordable supply of electricity, including, but not limited to, demand-side alternatives such as targeted energy efficiency, ultraclean distributed generation, as defined in Section 353.2 , and other demand reduction resources."

[26] According to GO 131-D Section IX.B.1.f, "an application for a permit to construct need not include either a detailed analysis of purpose and necessity, a detailed estimate of cost and

Footnote continued on next page.

alternatives only if a CEQA Environmental Impact Report is prepared. CEQA Negative Declaration documents typically do not consider alternatives. Hence, the identification of deferral opportunities is not always part of the GO 131-D or CEQA process as suggested by IOU comments.

The IOU's should be identifying all planned investments that may also be Pre-Application Projects designed to address grid needs in their GNA/DDORs pursuant to the *May 7, 2019 Ruling* and D.18-02-004. This includes all grid needs subject to Commission jurisdiction, including all substation and sub-transmission system needs that may be deferable by DER through the 10-year planning horizon (Reform No. 7). To support monitoring of DIDF and GO 131-D interactions, the IOUs should identify DIDF overlap in their updates to Energy Division's CEQA Unit on upcoming permitting work. As stated by SDG&E, the IOUs already provide quarterly reports of all GO 131-D projects to the Commission. When updating Energy Division, the IOUs should also identify the distribution and sub-transmission components of transmission projects in their quarterly AB 970 reports[27] that will be considered in the DIDF and provide best-available cost details. Should the AB 970 reports be superseded or suspended,[28] then the IOUs should provide this information to Energy Division with the successor report (Reform No. 36).

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economic analysis, a detailed schedule, or a detailed description of construction methods beyond that required for CEQA compliance."

[27] Pursuant to D.06-09-003, the IOUs submit quarterly AB 970 reports providing the planning and construction status, expected cost, and other details about electric transmission projects.

[28] On April 1, 2020, PG&E filed a Petition to Modify D.06-09-003 (Proceeding I.00-11-001) requesting that its quarterly AB 970 reports on transmission projects be suspended and replaced by a the Stakeholder Transmission Asset Review (STAR) Process which includes the filing of detailed reports about transmission projects on a semiannual basis. The petition states, "the information required by the AB 970 Quarterly Report will now be provided to the Commission through the STAR Process."

5. Requests for Offers

This section addresses items 5, 23, 24, 25, IPE N, and IOU f from the *November 8, 2019 Ruling* (*see* Attachment B to this *Ruling*).

5.1. Procurement Process Review, Monitoring, and Reporting

5.1.1. Party Comments

GPI stated that the screening and ranking process inappropriately reduces the list of deferral opportunities to a small fraction of the planned investment list. Changes to the DIDF are critical to salvaging its ability to effectively integrate DER solutions into the distribution system, says GPI. The best near-term adjustment is to increase the number of deferral opportunities included in the RFOs. GPI recommends that the Tiered Prioritization methodology be eliminated, or the IOUs should be required to employ a standardized, quantitative approach based on established quantitative benchmarks and pre-defined rubrics for the qualitative inputs.

CESA stated that the Commission should consider processes by which the DPAG stakeholders could potentially arrive at and present consensus recommendations, if such consensus can be reached prior to the Advice Letter filing, in order to minimize the risk of protests to Advice Letters that could delay an RFO launch. CESA notes that although Energy Division was timely and efficient in its review of PG&E's executed-contract filings in 2019, the utility contracting process could be streamlined. PG&E, for example, took approximately six months from shortlisting projects to executing contracts. CESA believes that the contracting timeline could be shortened.[29]

[29] *See* PG&E Advice Letter 5707-E.

PG&E states that the DIDF Advice Letter and RFO process generally has been successful and does not require changes beyond annual refinement through the application of lessons learned and participant feedback. PG&E only recently completed its first DIDF RFO cycle, which resulted in the execution and approval of three DER contracts. PG&E increased the RFO bid window, identified locations with charging constraints prior to solicitation, and during PG&E's second DIDF cycle. Rather than modifying the RFO process, streamlining the regulatory process would have the largest impact on DIDF outcomes.

SCE encourages the Commission to review/approve Advice Letters requesting DIDF RFO launch in an accelerated manner to be better align with their annual Queue Cluster interconnection process timelines commencing in April. In particular, SCE supports establishing a DER procurement concept, similar to the AB 57 Bundled Procurement Plan for energy procurement, which would provide utilities pre-approved authorization for procuring DERs for distribution deferral pursuant to Commission-established upfront procurement standards.

5.1.2. Discussion

While the IOUs' concerns about increasing regulatory filings and potential to hamper rather than improve DIDF outcomes are understandable, this *Ruling* agrees with GPI's arguments that that more deferral opportunities should be tested in the RFOs. Yet this *Ruling* does not agree that eliminating the screening and prioritization process is the best approach. Instead, adjustments to the prioritization process and standardization are discussed in Section 5, Prioritization Metrics, and the timing screen is discussed Section 4.6, Grid Needs and Deferral Screens. Here, a reasonable near-term adjustment would be for Energy Division and DIDF stakeholders to request that the IOUs present new or alternate deferral opportunities for analysis during the DPAG review process (Reform No. 39). If the IOUs disagree with Energy Division's assessment of which deferral opportunities should be included in the RFOs, then Energy Division should consult with Assigned Commissioner and ALJ.

Where agreement on deferral opportunities to pursue is achieved, however, the associated RFOs should proceed quickly. Hence, a separate DIDF Tier 2 Advice Letter should be filed by the IOUs that requests approval to forgo inclusion in a DIDF RFO of any candidate deferral opportunities identified (1) in IOUs GNA/DDOR filings; (2) by DPAG stakeholders; or (3) by Energy Division. Energy Division can then evaluate the DIDF Advice Letter requesting to launch RFOs separately from the second Advice Letter. Energy Division would review the second Advice Letter in consultation with the Assigned Commissioner and ALJ to decide how best to proceed (Reform No. 40). This *Ruling* reminds parties that the DIDF process is one of continual improvement and refinement, and this approach may be revisited in the future to ensure sufficient and appropriate numbers of deferral opportunities are included in the RFOs.

This *Ruling* agrees with CESA that the DPAG should include opportunities for stakeholders to arrive at and present consensus recommendations. While it would be helpful to shorten IOU contracting timelines, in the case presented by PG&E Advice Letter 5707-E, a 90-day extension was granted by the Commission due to need changes and the timing of interconnection reports.[30] To address this ongoing challenge, seeking to procure above the minimum operational requirements or including this option in contracts if it remains cost effective to do so would be appropriate (*see* also Section 6.5, Contingency Planning and

[30] PG&E Advice Letter 5707-E at 11 to 12.

Contingency Cost Recovery). In addition, PG&E's DIDF RFO Protocol schedule should reflect the requirement that the filing to Energy Division upon contract execution must occur in June if the approval to launch the RFO is received in December the previous year (within 6 months).[31] PG&E's 2020 DIDF RFO Solicitation Protocol stated that with "CPUC Approval of RFO" on December 16, PG&E would "File transactions for CPUC Approval" on September 1 (at 4).

Energy Division and the IOUs should explore opportunities to further streamline contract execution. For example, the IOUs are currently required to file a Tier 2 Advice Letter for contract approval within 6 months of approval of their DIDF solicitation.[32] If the forecast and operational requirements do not change, however, filing an Advice Letter for contract approval is an extra step that could be eliminated. The request to procure by solicitation would have already been approved. Instead, an "Information-Only Submittal" as defined by GO 96-B could be filed to Energy Division upon contract execution that includes a project description, summary of bid and procurement outcomes, the executed contract (in full and without redactions), and any other information as required by Energy Division (Reform No. 41).

Similarly, the *May 7, 2019 Ruling* requires the IOUs to file a Tier 2 Advice Letter to explain changes to DIDF project operational requirements subsequent to the November 15 filing date for approval to launch DIDF RFOs. But this additional step need not apply to minor changes that do not impact deferral viability. These minor changes should still be discussed with Energy Division.

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[31] Proceeding R.14-08-013, *Ruling on the Application of the Competitive Solicitation Framework for Distribution Investment Deferrals in the Distribution Resource Planning Proceeding*, November 19, 2018 at 6.

[32] *Ibid*.

This *Ruling* adds that changes to cost caps (deferral values) and planned investment costs subsequent to the November 15 filing date should also be reported by Advice Letter, unless so minor as to not impact deferral viability (Reform No. 42).

Extension requests should go to the Energy Division Director in cases where changes to DIDF project operational requirements delay contract execution beyond 6 months from the time of approval to launch the solicitation. This was a compliance timeframe established by Ruling.[33] It would be more efficient for the IOUs to request extensions from the Energy Division Director than the Commission's Executive Director.[34] The extension request should explain the reason for the request, propose an extension timeframe, and provide a rationale for the requested timeframe (Reform No. 43).

5.2. IOU Ownership

5.2.1. Party Comments

CUE states that holding a procurement with no restrictions on which entity can bid would maximize participation and lead to the most cost-effective solutions. CESA supports allowing IOU-owned DER projects to be considered as part of the DIDF process. In particular, CESA sees advantages in allowing for IOU-owned projects for planned investments with less than 3-years lead time, especially if projects can take advantage of IOU-owned land and expedite interconnection processes. However, CESA requests that the appropriate controls be in place to ensure a level playing field and refers to the framework in Appendix A of D.19-06-032 as a starting place for developing the appropriate controls. CESA recommends stakeholder review and comment on the

33 *Ibid.*

34 Commission Rules of Practice and Procedure, 16.6, Extension of Time to Comply.

framework. CESA further requests that forecast and planned investment details must be made equally available to third parties and the evaluation criteria thoroughly assessed to ensure projects are evaluated fairly without bias toward ownership model.

SIEA states that while the IOUs are not permitted to own BTM resources, there is nothing that precludes an IOU from proposing a FTM DER solutions as the "default" distribution equipment against which third-party owned DERs must compete. For example, an IOU could propose a FTM storage solution as a distribution capacity system (as opposed to transformer upgrades or some other traditional measure). The DER bidders would then seek projects that could beat the net cost of that solution (*i.e.*, after wholesale market revenues).

GPI states that IOU ownership may help close the operational knowledge gap, leading to improvements in the DIDF, associated RFOs, and ultimately more third-party DER solutions. Lessons learned be integrated into ongoing refinements to the DIDF (*e.g.* adjusting timing screen, prioritization metrics, *etc*.) to improve RFO outcomes. GPI's reply clarifies that they support IOU ownership insofar as an implementation framework is established to ensure third parties can still successfully compete.

SDG&E agrees with the other stakeholders that IOU-ownership of DERs and IOU-offer submission should not be precluded in DIDF RFOs. Arrangements for utility-owned generation should not be so prescriptive that it limits the IOU's ability to seek the most economical and best-fit solution: SDG&E considers third-party engineering, procurement, and construction; build, own, transfer; and/or third-party ownership with power purchase agreements as potential solutions. The increased offer competition that would result from allowing utilities to participate in a solicitation for DERs should lower costs and provide benefits to consumers.

In reply, SDG&E says that IOU ownership of DERs and participation in RFO solicitations are both feasible and beneficial for customers. SDG&E notes that IOU-owned DER solution should not be considered a traditional capital investment and not be deferrable as part of the DIDF process. In response to SCE's concern about the appearance of an unfair advantage to the IOUs, SDG&E states that it has implemented internal controls to prevent inappropriate communication between individuals responsible for the development of utility-owned DER solutions that could be offered into an RFO solicitation and the individuals responsible for executing the RFO.

PG&E states that they would potentially be interested in an option to consider IOU ownership of DER solutions via the DIDF framework, where appropriate if stakeholders are supportive. They state that the intent of the DIDF has been to identify candidate deferral opportunities for third-party ownership. The IOUs should not identify types of DER solutions, says PG&E, as such a requirement is outside the scope of the DIDF and the market should be offering DER solutions rather than the IOUs dictating DER solutions. PG&E does not believe anything prohibits the IOUs from procuring DER solutions.

If the potential for IOU ownership is desired, PG&E says that it would not bid on behalf of developers. Rather, PG&E would identify in its Advice Letter requesting RFO launch which opportunities it would seek authorization to solicit third-party owned along with design-build-transfer DERs or engineering, procurement, and construction bids to compete with third-party bids. PG&E would choose whichever bid under the cost-effectiveness cap is the most cost effective, safe, and reliable. Given that cost recovery of any service other than distribution deferral is recoverable via Energy Resource Recovery Account processes, PG&E would be procuring such services on behalf of its bundled customers. Therefore, PG&E says that it would need to consider each opportunity individually to determine what need and benefit would be provided to bundled customers. To facilitate IOU ownership more broadly, re-examination of cost recovery and cost allocation would be necessary, says PG&E.

PG&E believes that partial ownership of a potential DER solution to meet a deferral need is unnecessarily complicated, although PG&E is not opposed to it being allowed. F urthermore, even in cases of IOU ownership, third parties should be allowed to seek additional value to the extent it doesn't conflict with the requirements of the solicitation.

SCE finds that IOU-owned and operated DERs should be considered an option to meet electric system needs in lieu of a traditional wires solution, but at present, SCE deems it impractical for IOU-owned DERs to compete against third-party DER bidders in an RFO where SCE is performing the procurement and valuation. SCE states that it is administratively burdensome and/or cost prohibitive to maintain communication barriers that preclude IOU DER development teams access to non-public information that could create a perception of unfair advantage. That said, SCE believes that IOUs should not be precluded from participating as a bidder in procurement activities if appropriate barriers are established.

At present, SCE believes there are opportunities for both IOU-owned and third-party procured DERs to be considered to meet electric system needs in that SCE could evaluate if an IOU-owned DER is cost effective if third-party procurement is unsuccessful. In this case, IOU-owned DERs could be considered if SCE determined it to be more cost-effective than the traditional solution. For example, says SCE, they conducted their GNA/DDOR process in 2019 to determine which planned investments would be cost-effective and prepared a list of Tier 1 deferral opportunities by applying their prioritization metrics. SCE states that it would be appropriate for SCE to consider an IOU-owned DER solution for Tier 1 opportunities should third-party procurement be unsuccessful.

SCE states that it continues to seek out avenues to integrate DERs to meet grid needs that do not necessarily require participation in DIDF RFO procurement. Furthermore, IOU ownership of DERs should not be limited to specific use cases, says SCE but, rather, be analyzed as a potential cost-effective alternative for all applicable scenarios.

5.2.2. Discussion

This *Ruling* agrees with the parties that IOU ownership should be allowed but that the playing field should also be level between bidders. In line with D.19-06-032 that implemented the AB 2868 Energy Storage Program and Investment Framework, when procuring energy storage systems through competitive RFOs, the IOUs should consider all forms of resource ownership (*e.g.*, utility-owned, third-party owned, customer-owned, joint ownership). The RFOs should allow bid participation and evaluation without any bias towards an ownership model. It is unclear at this time, however, what controls or policies, if any, should be required to unsure parties do not have an unfair advantage. SDG&E believes it already has the necessary internal controls in place. At this time, this *Ruling* agrees with GPI that allowing for IOU ownership would increase overall understanding, that could lead to improvements in the DIDF and associated RFOs via future reforms based on lessons learned. Policies to ensure fairness should be revisited as needed based on 2020-2021 DIDF cycle outcomes (Reform No. 44).

This *Ruling* agrees with CESA that forecast and planned investment details must be made equally available to third parties with a sufficient level of detail and the evaluation criteria thoroughly assessed to ensure projects are selected without bias toward ownership model. Given PG&E's comments regarding potential complications with IOU ownership related to Energy Resource Recovery Account processes, it is reasonable that the IOUs each describe such issues from their perspective (if any) and present solutions as necessary in their recommendations for DIDF reform presented in the 2020 GNA/DDOR filings (Reform No. 45).

5.3. Incrementality and MUAs

5.3.1. Party Comments

CESA and SEIA believe that reforms to the incrementality rules are long overdue. SEIA states that the current incrementality framework has limited the participation of BTM DER resources in utility DIDF solicitations. GPI strongly supports expanding the ability of the DRP to enable and leverage the benefits of customer choice/BTM DERs to the distribution grid.

Specifically, CESA recommends refinements to how incrementality is assessed relative to the planning assumptions that are generated by the CEC and disaggregated down to specific circuits and feeders by the IOUs. There are varying levels of uncertainty or inaccuracies related to the location, growth trajectory, and operational profile of DERs that go into these planning assumptions, says CESA. When procured, BTM DERs may deviate to varying degrees from these assumptions. For example, for non-residential standalone storage systems, it is very difficult to predict or forecast charge and discharge behavior due to fluctuations in customer load and the need to mitigate non-coincident demand charges.

CESA cites to a clarification in D.19-08-001 on SGIP-funded energy storage projects that informs incrementality for the DIDF RFOs.

> *Customer payment or reduced rates received for enrollment in an economic DR [demand response] program integrated into the CAISO or the DRAM [demand response auction mechanism] is considered payment for services, not an incentive. As such, SGIP PAs should not, at this time, reduce SGIP incentives for any SGIP project that also is enrolled in an economic DR program integrated into the CAISO or the DRAM.*[35]

CESA argues that D.19-08-001 differentiated SGIP as an incentive program for installed storage systems that meet upfront eligibility requirements in contrast to a payment for grid services such as for energy storage systems that participate in DR programs or procurement mechanisms.

CESA also points to guidance from its 2018 proposal documented in the MUA Final Report for proceeding R.15-03-011 (*Order Instituting Rulemaking to Consider Policy and Implementation Refinements to the Energy Storage Procurement Framework and Design Program and Related Action Plan of the California Energy Storage Roadmap*).[36] There, CESA proposed an additional MUA rule (Rule 12) in the MUA Final Report to help address "varying 'black box' approaches to assessing the incrementality of offers [that] increases barriers to and uncertainty in the solicitation process, which increases costs to ratepayers." Overly

[35] D.19-08-001 at 66.

[36] *See* Appendix A of SCE, PG&E, and SDG&E, compliance report on behalf of the MUA working group filed in R.15-03-011, August 9, 2018 at 60-78, here: http://www3.sce.com/sscc/law/dis/dbattach5e.nsf/0/0EF9A015334951F8882582E4007ACC53/$FILE/R1503011-SCE%20MUA%20Working%20Group%20Report.pdf

conservative incrementality determinations, states CESA, can lead to over-procurement, requiring ratepayers to pay for more services than necessary.[37] Specific to SGIP, CESA stated in the MUA Final Report that industry stakeholders and the IOUs appear to agree that while the SGIP program has grid service objectives, a specific grid service is not being provided or procured through SGIP. SGIP's rules require certain amounts of charging and discharging but not the provision of specific grid services. Thus, because no operational profile of an SGIP-funded system can be assumed with sufficient certainty, the receipt of an SGIP incentive has no bearing on the determination of incrementality in the procurement process.[38]

PG&E states that NEM and SGIP resources can participate in their DIDF RFOs as long as they provide an incremental service that is not already compensated for in other proceedings and meet the required DIDF RFO dispatch requirements. PG&E said that it plans to test whether its Tier 1, FMC 1101 Project deferral opportunity from its 2020 DIDF RFO can be deferred by using the grid resource design element from one or more vendors in its local Energy Efficiency program solicitation. PG&E provided to potential bidders information about incrementality in its 2020 DIDF RFO information packet and further clarified PG&E's approach to incrementality in their DIDF RFO Questions and Answers document.[39]

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[37] *Ibid* at 69.

[38] *Ibid* at 70.

[39] *See* PG&E's *2020 DIDF RFO Questions and Answers*, February 7, 2020, at Section C, Incrementality, in the DIDF Q&A document located under the Additional Documents and Materials heading here, https://www.pge.com/en_US/for-our-business-partners/energy-supply/electric-rfo/wholesale-electric-power-procurement/2020-didf-rfo.page.

SCE states that it coordinates, where possible, with other DER procurements through evaluating DIDF bids for several services including RA and allow bidders to propose partially incremental offers. Given that IOU customer programs are already accounted for in the IEPR load forecast, and by extension distribution planning, SCE says that any resources procured through RFO based solutions should be incremental to IOU customer DER programs. SCE does not allow projects receiving benefits through other tariffs or programs to propose fully incremental offers. SCE, however, following the incrementality definitions, does allow the bidders to propose partially incremental offers that provide material enhancements to an existing project and can be considered incremental. Bidders must provide a feasible method of measuring and quantifying the incremental value to justify additional compensation. SCE provides an Incrementality Matrix to potential bidders to describe its overall approach.[40]

SDG&E states that DERs participating in NEM or SGIP should not be considered incremental for purposes of establishing eligibility to participate in a DIDF solicitation process. SDG&E has previously proposed that DERs that are not subsidized and forecasted through such tariffs and programs may be considered incremental for the purposes of establishing eligibility to participate in a DIDF solicitation process. CUE agrees with SDG&E.

In reply, CESA states that across the IOU comments, it becomes clear that incrementality policies are IOU-specific even though they should be statewide.

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[40] A February 4, 2019 version of SCE's matrix is publicly available as *Attachment D, Incrementality Matrix*, here: http://www3.sce.com/sscc/law/dis/dbattach5e.nsf/0/96F718F513914D9088258397007FD4F4/$FILE/R1410003-SCE%20Utility%20Regulatory%20Incentive%20Mechanism%20Pilot%20Report-PUBLIC.pdf

For example, while SDG&E argues that NEM and SGIP resources are not incremental, SCE allows for partial incrementality of such resources with the caveat that bidders must make a showing and demonstrate their incremental value. CESA finds inconsistent incrementality policies among the IOUs are unreasonable, as it creates uncertainty to bidders. CESA finds incrementality assessment methodologies should not be opaque and unclear because it places a significant burden on bidders (PG&E[41] and SCE) and should not be unduly discriminatory and contrary to Commission policy in making NEM/SGIP resources ineligible altogether (SDG&E).

5.3.1.1. Party Comments Specific to Resource Adequacy

PG&E and SDG&E did not comment specific to RA. SCE states that they evaluate DIDF RFO bids on several services including RA. During bid evaluation, SCE assumes that DERs procured through the DIDF will provide RA to the fullest extent allowed by the Commission and CAISO Rules. SCE notes, however, that current rules prohibit provision of distribution deferral and RA at the same time. Given that RA is provided on a monthly basis, current rules require that the DIDF resource be removed from the RA supply plan for the duration of any month in which the resource may be needed for distribution services. In practice, this means removing the resource from the RA plan for most or all of the summer months, says SCE, and because RA value is far higher during these months than the off-peak months, this means that RA value is limited.

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[41] At the time of their comments, CESA did not yet have access to PG&E's *2020 DIDF RFO Questions and Answers*, February 7, 2020, at Section C, Incrementality, in the DIDF Q&A document located under the Additional Documents and Materials heading here, https://www.pge.com/en_US/for-our-business-partners/energy-supply/electric-rfo/wholesale-electric-power-procurement/2020-didf-rfo.page.

SCE believes that the current MUA rules were created out of an abundance of caution. Further analysis may indicate that a DIDF resource may be able to also meet an RA obligation, without impacting the performance of either service. SCE recommends that the Commission consider revisiting the prohibition of DIDF resources from also providing RA; such consideration would need to be coordinated with CAISO's current initiative to reform RA, says SCE. CAISO's proposal to assign a resource-specific metric to indicate each unit's expected availability (the Unforced Capacity or UCAP value) may provide an opportunity to consider enabling RA value for MUAs.

5.3.2. Discussion

This *Ruling* agrees with CESA that the IOUs have a duty to explain their positions with respect to incrementality, and the approach among the three utilities should be consistent. PG&E's language regarding SGIP, NEM, and Energy Efficiency provides the clearest explanation for DIDF RFO bidders to date. The other IOUs should adopt similar language (Reform No. 46). PG&E's clarifying language reads as follows:

> ***Question C.1:*** *Can projects receiving SGIP funding be considered fully incremental?*
>
> ***Answer C.1:*** *Yes, as long as the project commits to meeting the dispatch requirements described in the protocol and pursuant to the TNPF [Technology Neutral Pro Forma agreement]. As noted in Table IV.1 of the protocol, SGIP projects that provide an incremental service will be considered fully incremental. SGIP projects do not currently have an obligation to respond to utility dispatch signals. As a result, committing SGIP capacity to meet the dispatch requirements would be considered an incremental service above and beyond what is compensated via SGIP. Any SGIP-incentivized storage project*

that provides the services solicited in this RFO would be considered wholly incremental. The project will receive the full IOU payment for the services procured under this RFO irrespective of any additional SGIP incentives payments it may receive. SGIP projects must still meet all applicable SGIP requirements in order to obtain SGIP incentives, and bidders should direct questions specifically about SGIP eligibility to their respective program manager.

Question C.2: *Can projects already compensated through NEM be considered fully incremental?*

Answer C.2: *Projects compensated under the NEM tariff that make a material enhancement in order to provide services solicited in this RFO (e.g., the addition of storage that commits to meeting the dispatch requirements described in the protocol and pursuant to the TNPF) would be considered wholly incremental. NEM projects without material enhancement are not considered incremental.*

Question C.3: *How can new energy efficiency projects demonstrate incrementality?*

Answer C.3: *This RFO provides two methods to demonstrate incrementality. Participants can choose a program specific review, whereby Participants describe their proposed energy efficiency measures and targeted market segments in Section V. Resource Double Payment/Double Counting of Appendix B and demonstrate that the projects do not overlap with PG&E's existing programs. If a proposed program does overlap with PG&E's existing EE programs, PG&E will estimate the degree of overlap. Program incrementality using this method could range from 0% to 100%. Alternatively, Participants can opt to use a pre-specified overlap method which does not require Participants explicitly demonstrate incrementality. With this*

> *approach, Proposed programs are automatically assumed 80% incremental and their contribution to the DIDF MW target is discounted by 20%. Assuming PG&E has a 1 MW DIDF target, a project using the haircut method would need to deliver approximately 1.2 MW in order to meet the DIDF need.*
>
> ***Question C.4:*** *Can projects already in PG&E's Energy Efficiency portfolio be considered fully incremental?*
>
> ***Answer C.4:*** *Projects that are included in PG&E's EE program portfolio are by definition NOT considered incremental and would need to make a material enhancement for the purpose of providing services solicited in this RFO that is clearly demonstrable above and beyond the scope of the original program in order to be considered wholly incremental. As described in Section IV.C of the protocol, offers for EE projects can either be evaluated for incrementality through a project-specific review or based on a pre-specified overlap factor.*[42]

This *Ruling* disagrees with SDG&E's position that SGIP should not be considered incremental for purposes of establishing eligibility to participate in a DIDF solicitation process but decline to comment with respect to incrementality for other customer programs at this time. SCE and SDG&E should carefully consider PG&E's February 7, 2020 clarifying text for SGIP, NEM, and Energy Efficiency incrementality in DIDF RFOs and either adopt the same text in their DIDF RFO materials or provide similar text that clarifies the IOU's position such that bidders can prepare bids. Common text among the three IOUs is strongly encouraged. Bidders should not need to confer with the IOU to understand SGIP

[42] *See* PG&E's *2020 DIDF RFO Questions and Answers*, February 7, 2020, at Section C, Incrementality, in the DIDF Q&A document located under the Additional Documents and Materials heading here, https://www.pge.com/en_US/for-our-business-partners/energy-supply/electric-rfo/wholesale-electric-power-procurement/2020-didf-rfo.page.

and NEM incrementality for DIDF bids. Instead, the clarifying text should be sufficient on its own.

In addition to clarifying IOU positions on incrementality as described above, this *Ruling* agrees with SCE and CESA that the MUA rules need to be revisited more comprehensively, including those related to RA. However, this *Ruling* decline to further address these issues at this time.

In response to SCE, this *Ruling* identifies an area for further review with stakeholders. It is not clear how, why, or to what extent a "prohibition" (as stated by SCE) currently exists on DIDF resources providing both RA and distribution deferral services. For example, if a single battery storage facility provided 5 MW of RA capacity and 5 MW of distribution deferral capacity it would be capable of simultaneously serving as both an RA resource and distribution deferral resource. This capacity-differentiated DER may have interconnection requirements (*e.g.*, charging restrictions) but should be able to address the two separate needs, and if so, this should increase the overall cost-effectiveness of the DER.

5.4 Day-Ahead Dispatch Requirements

5.4.1. Party Comments

The IPE recommended that the IOUs reconsider day-ahead dispatch requirements such that event-driven DER projects are more amendable to developer bidding (IPE N from the *November 8, 2019 Ruling*). SCE had indicated to the IPE that the Technology Neutral Pro Forma Agreement requires day-ahead dispatch of DERs. For projects that have real-time needs (event driven) this would require that the DER be dispatched every day regardless of whether the event occurs, according to the IPE, and could make DER solutions less cost effective. SCE responded to the *November 8, 2019 Ruling* that the day-ahead dispatch requirement does not limit developer opportunities or make projects less desirable and presented several supporting reasons for the requirement. They stated that the requirement reflects that SCE notices all events in the day-ahead timeframe, and that developers need to have their energy scheduled in the day-ahead market.

SDG&E responded that operational requirements and dispatch should align with the need and optimize value for all parties. SDG&E complies with direction to accommodate stakeholder requests for only day-ahead dispatch.

5.4.2. Discussion

The IPE Report on SCE's 2019 GNA/DDOR filing raised the issue that SCE's approach to dispatching event-driven DER's in the day-ahead timeframe may reduce developer interest in bidding.[43] SCE replies with arguments to support their approach. SCE states: (1) the CAISO market procures ancillary services day ahead and not real time; and (2) SCE's contract structure is designed for flexibility and market revenues for developers.

This *Ruling* agrees with the IPE that interactions between DER purchase agreements, CAISO bidding and settlement processes, and developer value stacking are complex and warrant scrutiny. SCE's approach might impact the desirability of DER solutions as well as the calculation of prioritization metrics (*e.g.*, cost-effectiveness and its LNBA/MWh-year component). H owever, SCE makes thoughtful points in reply. An opportunity to explore this issue further is provided by the event-driven DER solicitations from SCE's 2019 DIDF RFO. One example is the Saugus-Newhall No. 1 and No. 2 66-kV Sub-transmission Line Project. SCE should report the results of their event-driven projects included in

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[43] *Independent Professional Engineer SCE 2019 GNA/DDOR Report*, Nexant, November 5, 2019 at 53.

the RFO to Energy Division, the IPE, and participants of the 2020 DPAG and include a discussion in their recommendations for potential DIDF reforms in their 2020 GNA/DDOR filing. PG&E and SDG&E should also consider SCE's day-ahead dispatch requirement in their recommendations for potential future DIDF reforms (Reform No. 47).

5.5 Contingency Planning and Contingency Cost Recovery

5.5.1. Party Comments

CESA and SEIA support the incorporation of excess DER capacity procurements where cost effective in comparison to traditional solutions. CESA adds that this concept is already being pursued in practice as contracts are negotiated and the IOUs are made aware of new information (*e.g.*, updated load forecasts), whereby contracts are executed for capacity with an excess margin to account for forecast uncertainty or as a contingency measure for deployment-related failures or shortfalls. Instead of addressing changes in load forecasts by modifying and putting projects back out to bid, says CESA, forecast uncertainty issues can be more efficiently addressed by incorporating options within contracts that allow them to adapt to growing needs. CESA believes that such risk mitigation practices are reasonable and should be reflected in the DIDF process when assessing and prioritizing projects. Specifically, the standard pro forma contracts should allow the IOU to procure more capacity as needed if still cost-effective. These capacity add-on options would be approved as part of the contract approval process for the DIDF RFO, even as the IOUs are procuring against the original need, says CESA.

CUE states that DERs are, by their nature, less reliable than wires solutions. Since more than one kW of DERs must be acquired to replace a kW of wires to achieve a similar result, there must be excess capacity of DERs acquired to replace wires solutions. The cost of this excess capacity must be factored into cost-effectiveness comparisons, says CUE.

Public Advocates states that when an IOU finds that the original grid needs have changed while in the process of contracting for a DER solution, the IOU could still proceed with a DER solution to meet that changed need if the cost of the DER solution changes but remains lower than the cost of the traditional solution. DERs should not be used in circumstances where the traditional project would be more cost effective, says Public Advocates.

PG&E supports the use of a Cost-Effectiveness Cap to fairly assess DER cost effectiveness and states that outcomes in the DIDF should be evaluated in terms of customer savings, not DER MWs. SDG&E states that procuring "excess capacity" from DERs could impose unnecessary costs on customers. SDG&E believes the "Cost Effectiveness and Market Effectiveness" of DERs in comparison to traditional wires solutions are being fairly assessed under current solicitation processes. SCE states that over-procurement of DERs to possibly account for needs not yet forecasted could result in increased costs to solve grid needs and should not be implemented unless proven to be cost effective.

CESA's reply agrees with the parties that excess procurement should not occur if it exceeds the cost cap. If cost-effective, excess capacity procurement of DER solutions provides contingency value in mitigating risks of DER deployments not materializing as predicted as well as option value in mitigating load forecast risks, says CESA. The DER capacity needed plus contingency/option margin would still be in the ratepayer interest as it reduces costs and should thus be allowed. Despite procuring DER solutions beyond the capacity needed to address an overload, unnecessary costs would not be imposed on customers, rather, such excess procurement would be reducing costs but offering greater contingency or option value to ratepayers.

In addition, SCE reiterated its request that planning costs, including design and engineering costs of the traditional distribution system solution, in the Distribution Deferral Balancing Account be approved.[44] PG&E agrees with SCE and states that the treatment of contingency planning costs must be confirmed and cost recovery must be explicitly allowed as previously authorized by the Commission. PG&E explains that as reported in its Advice Letter 5707-E[45] which requested both DIDF DER contract approval and contingency plan cost recovery, leaving this issue unaddressed impacts the ability of IOUs to execute and get approval of DER contracts. While pre-approval of unknown contingency costs may not be possible, the Commission should make it explicit that IOUs can track and record reasonable costs for contingency costs in the memorandum account to seek cost recovery.

5.5.2. Discussion

This *Ruling* agrees with CESA and SEIA that excess capacity procurement can still be cost effective and agrees with the IOUs that excess capacity should be proven cost effective before being procured to resolve forecast changes. Changes in operational requirements after RFO launch continue to be a challenge for DER procurement. As stated by CESA, it would be reasonable to include options in contracts for excess procurement if it remains cost effective in comparison to the traditional solution. Thus, where forecast or operational requirements changes

[44] *May 7, 2019 Ruling* at 12-13 and Appendix E to August 23, 2019 *Amended Reports of Southern California Edison Company (U 338-E) of Its 2019 Grid Needs Assessment and 2019 Distribution Deferral Opportunity Report* at 3-4.

[45] PG&E referred Advice Letter 5688-E, but the reason for that reference is unclear.

occur post RFO launch, the IOUs would have a built-in mechanism to address the changes within the solicitation framework rather than relaunching the RFO (Reform No. 48). It is also reasonable that the IOUs identify DERs as the first contingency in their contingency planning process and consider full or partial IOU-ownership of DER solutions as a contingency if third-party procurement is unsuccessful (Reform No. 49). (*See* also Section 6.2, IOU Ownership.)

SCE previously raised concerns that spending on contingency planning is unavoidable, including design work, equipment, permitting, and other preconstruction activities that should not be suspended while projects are considered in DIDF RFOs. The *May 7, 2019 Ruling*[46] stated that the IOUs should be able to record such design and engineering work in the Distribution Deferral Balancing Account (DDBA). This *Ruling* clarifies that the IOUs can use the DDBAs to record contingency plan spending, however, these costs shall be fully itemized for review and approval in the IOU's GRC (Reform No. 51).

This *Ruling* stresses that Energy Division staff cannot pre-approve cost recovery of unknown future costs as requested in PG&E Advice Letter 5707-E (Reform No. 52). PG&E requested as a condition of AL 5707-E approval, that it be authorized "to recover the reasonable costs of the contingency plan, including any traditional distribution upgrades that may be required that are not actually deferred under the contracts."[47] Energy Division staff cannot bind the Commission to guarantee IOU cost recovery for contingency plans, but the costs are allowed to be "tracked" by the IOUs. The IOUs continue to be allowed to

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[46] *May 7, 2019 Ruling* at 13.

[47] PG&E Advice Letter 5707-E at 1

seek cost recovery for reasonable costs incurred through appropriate cost recovery venues, such as, GRCs.

While this *Ruling* recognizes the need for the IOUs to incur costs on contingency planning, I am concerned that the deduction of any contingency spending from the deferral benefit calculation would motivate the IOUs to frontload contingency spending, which could make distribution deferral unviable. Ordering Paragraph 2.dd. in D.18-02-004 required the IOUs, on their GRC filing year, to submit a report to the Commission with their GNA/DDOR filing on contracted DIDF project payments in comparison to spending on the deferred infrastructure. Confidential filings were allowed. Similarly, the IOUs should file a report with each GNA/DDOR that includes the latest cost details, which may only include contingency costs if a contract has not yet been executed for a deferral project. This reform would not conflict with or alter D.18-02-004, Ordering Paragraph 2.dd. Instead, it would create a supplemental filing requirement, and the reporting should include any modifications or additional details required by Energy Division (Reform No. 50).

5.6. Independent Evaluator Scope of Work

The May 7, 2019 *Ruling* did not comment on the IE scope of work; however, this *Ruling* clarifies that the IE (like the IPE) shall report directly to Energy Division to prepare its deliverables and conduct its analyses for DIDF implementation (Reform No. 53). The scopes of work for the IE for the 2019-2020 DIDF cycle varied by IOU. For the 2020-2021 DIDF cycle, the IE's scope of work is presented in Attachment C.

The term of the IE scope of work shall be the entire DIDF cycle, which starts on January 1st each year to plan for Pre-Distribution Planning Advisory Group (Pre-DPAG) and DPAG implementation and concludes on July 31st the following year after all RFOs are concluded and all DIDF reforms are implemented. IE scopes of work for each DIDF cycle will overlap. Planning for the next DIDF cycle will begin while RFO implementation and DIDF reform work is completed for the prior DIDF cycle. For RFOs that launch late, the IE contract would need to be extended for the associated DIDF cycle or as directed by Energy Division. Contracts with the IE should be timely executed by the IOUs to allow for IE participation in DPAG activities as soon as possible (Reform No. 54).

As shown in Attachment C, the IE's scope of work is defined within the Pre-DPAG, DPAG, and Post DPAG periods, although some of the work may be conducted earlier or later than the official start of these periods as defined by Energy Division for each DIDF cycle. The scope of work may be modified by Energy Division as needed for the IE to successfully complete each task. The IOUs will promptly submit a Tier 1 AL to notice changes in scope should they deviate significantly from the scope described in Attachment C. Minor changes should not necessitate an AL filing (Reform No. 55). IOU additions to the IE scope of work for DIDF RFOs should be presented to Energy Division for approval (Reform No. 56).

IT IS RULED that:

The parties shall comply with the DIDF reforms set forth above and in the Attachment A to this *Ruling*.

Dated May 11, 2020, at San Francisco, California.

/s/ ROBERT M. MASON III

Robert M. Mason III
Administrative Law Judge

ATTACHMENT A

Attachment A
List of DIDF Reforms

Implementation Timeframe for DIDF Reforms

1. Energy Division shall hold a stakeholder workshop to receive feedback on which reforms to prioritize for implementation in the 2020-2021 DIDF cycle and which to implement in the next DIDF cycle. Partial implementation for some reforms may be considered, with full implementation achieved for the next cycle. Energy Division shall make these determinations in consultation with the Assigned Commissioner and Administrative Law Judge.

General DIDF Reform Topics

Proceeding Status

2. In the DDOR list of planned investments, the IOUs shall identify all DER solutions planned for IOU ownership or otherwise planned for procurement but not prioritized as deferral opportunities. In addition to including the same data provided for every other planned investment, the types of DER selected for IOU ownership (*e.g.*, storage, energy efficiency, etc.) and indicator that the project is excluded from prioritization shall be defined in sortable columns. If no IOU-owned DER solutions are listed in compliance with this reform, the IOUs shall explain why in their GNA/DDOR filing.

Common Comparable Datasets

3. The same IEPR datasets shall be used by all three IOUs in the preparation of their GNA/DDORs. The IOUs shall meet and confer to establish which IEPR datasets are used for forecasting and disaggregation and present a listing of the selected datasets to Energy Division for approval. In all cases, IEPR datasets shall be used where feasible for disaggregation and forecasting and the IOUs shall clearly state in the GNA/DDORs which datasets where used, including whether the draft or updated IEPR datasets.

4. The IOUs shall provide tabulated summary tables showing the types and numbers of grid needs, planned investments, and candidate deferrals identified each cycle similar to the ones PG&E provided in their 2019 GNA/DDOR. Energy Division, in consultation with the IPE, will identify improvements and standards for the GNA/DDOR summary tables as needed for future DIDF cycles to support preparation of the IPE Post-DPAG Report.

5. The IOUs shall calculate LNBA values for both planned investments and candidate deferrals based on a 10-year timeframe. If a project need (*i.e.*, peak MW shortfall) is not identified for the entire 10-year period, the largest forecast need identified may be used (*i.e.*, peak MW shortfall for year 5). If the IOUs would prefer to use LNBA ranges for planned investments, then the ranges shall be tighter than those provided in 2019, and the use of ranges shall be subject to approval by Energy Division prior to implementation.
6. The GNA/DDOR filings shall include a description and listing of any DER-driven needs and the required equipment and steps taken by the IOU to develop any non-DER solutions to address the DER-driven needs. Steps planned or taken by the IOUs to upgrade monitoring and control systems to allow DERs to meet such needs shall also be described.
7. The IOUs shall apply a 10-year planning horizon for Pre-Application Project needs included in the GNA but continue to apply a 5-year planning horizon for all other needs presented in the GNA.

DRP Data Portals

8. The IOUs shall identify the location of all planned investments on their DRP Data Portal maps and in the attribute data and other data provided on the portals.
9. The IOUs shall identify the location of all approved transmission projects on the DRP Data Portal maps such that they can be viewed at the same time as Grid Needs Assessment, Distribution Deferral Opportunity Report, ICA, and other data layers provided. The transmission projects shall be sortable (by layer) for CAISO approved, Commission approved, and internally approved by IOU/CAISO and Commission approval not required. Among the attribute data provided shall be the approval date and expected operational date. Additional projects or attribute data may be requested by Energy Division for posting based on the IOU's quarterly Assembly Bill 970 transmission reports, successor reports, or other sources. Where the precise alignment or location is not yet known, an estimate should be provided with a note that siting is not yet complete.
10. The IOUs shall include the fire threat and tree mortality data from the online Commission FireMap[1] as layers on the DRP Data Portal online maps and ensure the added data layers remain current.

[1] https://ia.cpuc.ca.gov/firemap/

11. In their recommendations for DIDF reform submitted in the 2020 GNA/DDOR filings, the IOUs shall discuss a timeframe for adding detailed historical PSPS outage data to the maps and datasets hosted on the DRP Data Portals.

Grid Needs and Deferral Screens

12. The IOUs shall present all grid needs separately for the purpose of identifying planned investment and candidate deferral projects and applying the prioritization metrics to determine which projects to include in the DIDF RFO. For comparative purposes, the IOUs may also present prioritization results from combining grid needs for a deferral opportunity accompanied by an explanation of why the IOU believes the grid needs must be combined into a single deferral opportunity.

13. The IOUs shall continue to provide forecast loading data for all feeders, not just feeders with deficiencies and be careful to follow the GNA/DDOR requirements specified in Appendix A to the *May 7, 2019 Ruling* unless refined by this *Ruling*.

14. Specific to circuit-segment level (line segment) needs, the IOUs shall continue to perform and document the analyses as part of the GNA but may choose to list only the circuit segments for which needs are identified rather than listing all line segments in the GNA/DDOR filings. The IPE and Energy Division may request the entire listing of line segments as needed.

15. SDG&E shall include clear explanations in their GNA/DDOR filing for the removal of any grid needs due to phase balancing, transfer of loads, or the correction of SDG&E modeling issues.

16. In their recommendations for DIDF reform filed in the 2020 GNA/DDORs, the IOUs shall describe projects that may be feasible to defer by DER but do not meet the three-year timing screen and discuss the possibility of a shorter timing screen for implementation in the 2020-2021 DIDF cycle. The IOUs shall also discuss the requirements that would enable forecasts of circuit-segment and voltage and/or reactive power needs beyond three years.

Grid Modernization Plans and GRCs

17. The IOUs shall identify any equipment necessary to integrate DERs with the grid that could feasibly be owned by a third party and discuss the pros and cons of third-party ownership in their DIDF reform recommendations provided with the GNA/DDOR filings. High-level costs estimates shall be provided with any equipment identified including estimates for the amount of equipment to be required within the next 10 years.

18. The IOUs shall apply to their 2020 GNA/DDOR filings a grid need ID, facility ID, and project ID numbering system similar to the one in SCE's 2019 GNA/DDOR. All DIDF project ID numbers shall be unique and directly link to specific projects in an IOU GRC. Where the IOUs require differences in numbering approach due to internal organizational or database systems, they shall implement the custom approach for 2020 with an explanation in their recommendations for DIDF reform. Energy Division shall review the numbering approaches applied for the 2020 filings and approve the numbering systems to be used for the 2021 GNA/DDOR and future filings.

Prioritization Metrics

Prioritization Metrics Workbooks and Joint Template

19. The IOUs shall develop a common prioritization metrics spreadsheet template based on SCE's 2019 prioritization metrics workbook. It shall be called the ***Joint Prioritization Metrics Workbook Template***.

20. The IOUs will reach a common understanding of each label, heading, and formula used in SCE's 2019 prioritization metrics workbook and apply the same labels and formulas in the template or document any improvements to SCE's labels, headings, and formulas. The IOUs shall present their final, 2020 Joint Prioritization Metrics Workbook Template to Energy Division for approval on or before **June 1, 2020** or as determined by Energy Division.

21. All LNBA calculations shall be included in the IOU's 2020 prioritization metrics workbooks.

22. The Excel prioritization metric workbooks and LNBA data filed with the GNA/DDORs shall be fully unlocked and functional with all formulas in place and operable. Regardless of whether the IOUs believe the workbooks contain confidential data, they shall be provided to Energy Division. In parallel, the IOUs shall file a motion requesting confidential treatment if they believe specific data to be confidential. To the extent fully-operable Prioritization Metric Workbooks with all LNBA data included cannot immediately be made public upon filing, a complete PDF of all worksheets shall be filed in addition to the Excel workbooks with only the necessary redactions made.

23. At such time as Energy Division determines that further improvements to the prioritization metrics template, IOU-specific workbooks, or underlying metrics or data are to be made, Energy Division shall make this determination and require the IOUs to implement them, as time allows, for the current DIDF cycle or future ones.

Forecast Certainty Metric and Qualitative Assumptions

24. The IOUs shall include in the Joint Prioritization Metrics Workbook Template a ***table of guidelines*** to direct Forecast Certainty metric application. The table of guidelines will clarify factors that could delay or accelerate project need and establish "Likelihood of Project" numerical values. In addition:

    a. The IOUs shall review the design of the Year of Need and Likelihood assumptions of the metric to ensure one does not inadvertently dominate or override the other component and document the results of this review in the annotated Joint Prioritization Metrics Workbook Template. It may be that only one or the other assumptions should be applied to the metric.

    b. The IOUs shall describe all weightings they apply to combine the components of the Forecast Certainty metric into a single score.

    c. The need date shall be used for Forecast Certainty metric calculations. The expected operational date shall also be identified in the workbooks for informational purposes.

    d. For Pre-Application Projects, the IOUs shall still provide the Forecast Certainty metric data but shall not apply the calculated Forecast Certainty metric results to the prioritization ranking of these projects.

25. To further improve on SCE's 2019 prioritization metrics workbook, the IOUs shall:

    a. Annotate their 2020 workbooks to ensure all labels, headings, and formulas used are described and that each spreadsheet column has a defined heading.

    b. Seek to quantify all qualitative values and fully define such values within the workbooks. The quantification of qualitative values shall be based on ***scoring rubrics*** (*i.e.*, a table of guidelines) and include explanatory narratives.

    c. Fully describe and document all qualitative values that the IOUs determine not to be quantifiable, including the reason the values cannot be quantified.

Consideration of Value Stacking

26. The IOUs shall seek to satisfy multiple procurement objectives where feasible. In such instances, this may result in deferral projects that exceed the

cost cap because the procurement also satisfies other regulatory procurement objectives.

27. The IOUs shall provide narratives about expected value stacking opportunities for each candidate deferral in their GNA/DDOR filings and any requested by Energy Division. Among the concepts to discuss shall be compatible participation in various wholesale markets and other value streams from which the utilities would otherwise have spent capital.

28. To the extent PG&E already included value stacking within its 2019 prioritization metrics, this shall be discussed with the other IOUs as they complete their Joint Prioritization Metrics Workbook Template for Energy Division approval and the outcomes shared with the DPAG stakeholders as recommendations for potential future DIDF reform.

LNBA Data

29. The underlying LNBA data shall be provided, including discount rate, revenue requirement multiplier, inflation assumptions, O&M factor, and book life. These and any other key assumptions shall be included in the 2020 prioritization metrics workbooks filed by the IOUs. The IOUs shall tabulate all assumptions they used in the LNBA model, as well as provide the sources/basis behind these assumptions in their GNA/DDOR reports.

30. The IOUs shall include, for informational purposes, the LNBA/MWh-day value for each candidate deferral project in their 2020 prioritization metrics workbooks.

Cost Effectiveness Metric and Project Cost

31. The IOUs shall discuss in the 2020 GNA/DDORs the potential for 2021-2022 DIDF cycle reforms related to the IPE's recommendation about the general importance of the Cost Effectiveness metric.

32. In their recommendations for potential 2021-2022 DIDF cycle reforms, the IOUs shall consider GPI's comments about prioritization changing from a relative ranking among the candidate deferral projects identified each year to a ranking based on baseline/absolute threshold values that would carry over each year.

33. The cost of planned investments and deferral opportunities (unit cost) reported in the GNA/DDOR and applied to prioritization calculations shall include all deferable (unspent) costs, including regulatory and permitting costs. The cost shall reflect the total project cost based on the latest, most accurate information at the time of filing. Upon request, the IOUs shall be

prepared to itemize regulatory, permitting, or other costs that are already spent or otherwise not deferable.

34. If the cost of a planned investment or deferral opportunity conflicts with the corresponding project cost reported in an IOU's same-year GRC filing, the IOU shall, in the GNA/DDOR, identify the GRC-specific cost and explain the discrepancy. Pursuant to D.18-02-004, Ordering Paragraph 2h., the discrepancy must also be presented in the GRC testimony.

Pre-Application Projects

35. Pre-Application Projects shall be identified as Tier 1, 2, or 3 in the GNA/DDOR filings and ranked using the same prioritization metrics and methods applied to all other deferral opportunities (except as otherwise noted in this *Ruling*, *e.g.*, Forecast Certainty metric, Reform No. 24d). Once filed with the Commission in the form of an application pursuant to General Order 131-D, all Post-Application Projects will continue to be evaluated like any other deferral opportunity in the GNA/DDORs unless otherwise directed by the proceeding opened for the Post-Application Project.

36. The IOUs shall identify to Energy Division's CEQA Unit all projects that are expected to require General Order 131-D compliance within the 10-year planning horizon and have subtransmission or distribution components included in the DIDF on a quarterly basis (or as requested by Energy Division) and include data found in the Assembly Bill (AB) 970 or successor reports (*e.g.*, confidential cost, approvals required, and approval status). For each project identified, the IOUs shall indicate which approvals are required (*e.g.*, internal to IOU, CAISO, Commission) and, if the approvals have not yet been attained, when they are expected to be attained. Similarly, projects listed in the IOU's quarterly, AB 970 reports (or successor to the reports) with components included in the DIDF shall be identified to Energy Division at the time of AB 970 report or successor filing.

37. The IOUs shall include information about the approval status of Pre-Application and Post-Application projects in the GNA/DDOR narrative and spreadsheets (i.e., DDOR planned investment and deferral opportunities spreadsheet lists) and prioritization metrics workbook of deferral opportunities. For example: CAISO approval on, expected on [year or N/A]; Commission GO 131-D application (and type) filed on, expected on [year or N/A]; and internally approved by IOU on [year or TBD].

38. The IOUs shall clearly identify conflicts (if any) between the DIDF and General Order 131-D in their recommendations for DIDF reform in the 2020

GNA/DDOR filings. Where conflicts are identified, the IOUs shall also recommend solutions.

Requests for Offers

Procurement Process Review, Monitoring, and Reporting

39. At the request of Energy Division, the IOUs shall present new or alternate deferral opportunities for analyses during the DPAG review process.

40. The IOUs shall continue to file a Tier 2 Advice Letter recommending distribution deferral projects to be included in the DIDF RFO process. In addition, the IOUs shall file a separate Tier 2 Advice Letter on November 15th requesting approval to not include in the DIDF RFO process any remaining candidate deferral opportunities identified in their GNA/DDOR filings or by DPAG stakeholders or Energy Division.

41. The IOUs are required to file a Tier 2 Advice Letter for contract approval. If the forecast and operational requirements do not change, however, the IOUs need not file the Advice Letter for contract approval. Instead, an Information-Only Submittal (*see* General Order 96-B) may be filed with Energy Division upon contract execution that includes a project description, summary of bid and procurement outcomes, the executed contract (in full and without redactions), and any other information as required by Energy Division.

42. The *May 7, 2019 Ruling* requires the IOUs to file a Tier 2 Advice Letter to explain changes to DIDF project forecast and operational requirements subsequent to the November 15 filing date. This *Ruling* clarifies that a Tier 2 Advice Letter is also required for changes to cost caps (deferral values) and planned investment costs subsequent to the November 15 filing date.

    a. An Advice Letter need not be filed, however, for minor changes to forecasts, operational requirements, or cost caps that do not impact deferral viability. Energy Division staff shall still be notified of the minor changes.

43. When DIDF project contract execution is delayed, the IOUs may request an extension from the Energy Division Director rather than the Commission's Executive Director. The extension request shall explain the reason for the request, propose an extension timeframe, and provide a rationale for the requested timeframe.

IOU Ownership

44. The IOUs shall encourage bids for all forms of resource ownership (*e.g.*, utility-owned, third-party owned, customer-owned, joint ownership) in their

DIDF RFOs, allowing for bid participation and evaluation without any bias towards a specific ownership model. Procurement outcomes of the 2020-2021 DIDF cycle shall be reviewed during the 2021-2022 DIDF cycle at the discretion of Energy Division in coordination with the IPE and IE to determine if policies are required to ensure fairness among bidders.

45. The IOUs shall identify issues (if any) related to IOU ownership, Energy Resource Recovery Account cost recovery, and IOU procurement on behalf of bundled customers in their recommendations for DIDF reform in the 2020 GNA/DDOR filings.

Incrementality and Multiple-Use Applications

46. The IOUs shall adopt PG&E's February 7, 2020 clarifying text or develop similar text to clarify SGIP, NEM, end Energy Efficiency incrementality and include the text in their 2020-2021 DIDF RFO materials. The draft text shall be included in each IOUs GNA/DDOR as reform recommendations and then presented during the 2020 DPAG to receive feedback. The text shall be reviewed by Energy Division prior to RFO launch.

Day-Ahead Dispatch Requirements

47. SCE shall report the results of their event-driven projects included in the their RFO for the 2019-2020 DIDF cycle to Energy Division, the IPE, and participants of the 2020 DPAG and include a discussion in their recommendations for potential DIDF reforms in their 2020 GNA/DDOR filing. The discussion shall focus on how the approach taken by SCE impacts the desirability of DER solutions and the calculation of prioritization metrics (especially where LNBA/MWh-year is applied). PG&E and SDG&E shall also consider SCE's day-ahead dispatch requirement in their recommendations for potential DIDF reforms.

Contingency Planning and Contingency Cost Recovery

48. The IOUs shall include options in DIDF RFO contracts for the procurement of DER resources above minimum performance and/or operational requirements to the extent it remains cost effective. It follows that where forecast or operational requirements changes occur post RFO launch, the IOUs shall seek to address the changes within the solicitation framework to the maximum extent possible rather than relaunching the RFO.

49. The IOUs shall identify DERs as the first contingency in their contingency planning process, and where third-party procurement is unsuccessful, shall consider full or partial IOU-ownership of a DER solution.

50. With each GNA/DDOR filing, the IOUs shall append or separately provide to Energy Division a report organized by deferral opportunity that contains itemized data on any payments made to contracted deferral projects and all spending on contingency plans for each deferral opportunity. The reporting shall include any modifications or additional details required by Energy Division. The reporting shall include all candidate deferral projects launched in a DIDF RFO since 2018 and will continue to cover this timeframe unless modified by Energy Division. Additional reporting guidelines apply on GRC filing years pursuant to D.18-02-004, Ordering Paragraph 2.dd.

51. The IOUs are allowed to track contingency plan spending in their Distribution Deferral Balancing Account and seek recovery for costs reasonably incurred in their General Rate Case. Approval of any costs tracked shall occur in the General Rate Case. All contingency plan spending shall be itemized by DIDF RFO project for General Rate Case filings rather than summarized and aggregated.

52. The IOUs shall not request pre-approval of cost recovery for contingency plans in Advice Letters requesting approval of DIDF RFO contracts or otherwise make the approval of such requests a requirement for the Energy Division to approve DIDF RFO contracts.

IE Scope of Work

53. IE-specific reforms for the 2020-2021 DIDF cycle are implemented within the IPE Scope of Work presented in Attachment C. The IE shall report to Energy Division to prepare its deliverables and conduct its analyses for DIDF implementation.

54. IOU contracts with the IE for the full scope of work identified in Attachment C shall be executed by the IOUs to allow for IE participation in DPAG activities as soon as possible, ideally on or before **June 1, 2020** and as defined in Attachment C for all subsequent years.

55. The IE scope of work may be modified by Energy Division as needed for the IE to successfully complete each assignment. The IOUs will promptly submit a Tier 1 Advice Letter to notice changes in scope should a scope change differ significantly from the scope described in Attachment C. Minor changes should not necessitate an Advice Letter filing.

56. Any IOU additions to the IE scope of work for DIDF RFOs shall be presented to Energy Division for approval at least 10 days before IE contract execution.

(End of Attachment A)

ATTACHMENT B

Attachment B

Questions and Topics from November 8, 2019 Ruling Requesting Comments on Possible Improvements to the 2020 Distribution Investment Deferral Framework Process (R.14-08-013)

General DIDF Reform Topics

1. To what extent did the IOUs have **common, comparable datasets** for the 2019 GNA/DDOR filings and in what ways could the 2020 filings be improved in this regard?
   a. To what extent did San Diego Gas and Electric, specifically, provide GNA/DDOR data and documentation that was comparable in scope and detail to that provided by SCE and PG&E?

2. To what extent do the IOUs assert **confidentiality** over data that do not require confidential treatment or require overly burdensome processes for participant access to confidential materials? Please provide specific examples.

3. Should all planned investments be shown on the IOU's Distribution Resources Plans data portals (**online maps**). SCE Alberhill Substation was not shown on SCE's portal, for example. In what ways do discrepancies between the online maps the GNA/DDOR filings still exist that should be corrected.

4. What modifications would increase the likelihood that planned investments that address **voltage, reliability, and resiliency** needs are prioritized for deferral?
   a. Should **reliability and resiliency** needs be **separated** in the 2020 GNA and DDOR filings to allow for consideration of resiliency needs, specifically[2]; and
   b. Should the IOUs each identify a **value for lost load and/or resiliency value** and apply it to the prioritization metrics?

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[2] The adopted definition of the term, "reliability," pursuant to the Competitive Solicitation Framework (Decision (D.) 16-12-036) includes the term, "resiliency," as follows, "reliability (Back-Tie) services are load-modifying or supply services capable of improving local distribution *reliability and/or resiliency*. Specifically, this service provides a fast reconnection and availability of excess reserves to reduce demand when restoring customers during abnormal configurations." There is also a definition of, "resiliency," in D.16-12-036, which includes the term "reliability." It reads, "resiliency (microgrid) services are load-modifying or supply services capable of improving local distribution *reliability and/or resiliency*. This service provides a fast reconnection and availability of excess reserves to reduce demand when restoring customers during abnormal configurations."

IOUs already identify a cost associated with avoided outage minutes in their General Rate Case (GRC) filings, for example. This could be used in the interim for the 2019 DIDF cycle while resiliency values are, potentially, further defined in other CPUC proceedings.

5. When GNA/DDOR filings identify a planned investment that is a near-term need, *i.e.*, does not meet the timing screen for deferral by an RFO process, do the IOUs ever implement an **IOU-owned** and operated Distributed Energy Resources (DER) solution as the least cost or preferred solution? If not, each IOU should explain why. For disclosure purposes, should each IOU identify these types of DER solutions in their GNA/DDOR going forward, *e.g.*, in the list of planned investments not prioritized for deferral in the DDOR?

6. Should a **10-year planning assumption** and forecast apply to the identification of all transmission and subtransmission GNA components to better align the GNA with the 10-year DDOR data as directed by the May 7, 2019 Ruling?[3] Similarly, should a 10-year planning assumption apply to any distribution GNA component that is addressed by a DDOR planned investment to be reviewed pursuant to CPUC General Order (GO) 131-D that has transmission components that are not reported in the GNA/DDOR?[4] See also the Pre-Application Project section below.

7. Should all **reliability needs** identified in the GNA/DDOR filings be reliability needs that are earmarked within the planning horizon to require mitigation as defined in adopted reliability planning standard or guide (*e.g.*, load shedding would not be allowable under the associated IOU standard)? Should it be assumed that all reliability needs identified are those that the

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[3] May 7, 2019 Administrative Law Judge's Ruling Modifying the Distribution Investment Deferral Framework.

[4] For example, refer to the Estrella Substation project in PG&E's 2019 GNA/DDOR filing.

IOUs believe meet a threshold for cost-effective mitigation; a system can never be completely risk free.[5]

8. Should all GNAs include a **unique project ID** that links to a planned investment in the DDOR and to items included in IOU GRC. Refer to SCE's 2019 GNA/DDOR filing. Should it also be assumed that GRCs will include additional investments that do not have a GNA/DDOR project ID? Projects that involve equipment that cannot be deferred by DERs might include, for example, the addition of SCADA (supervisory control and data acquisition) equipment to add visibility to the operation of existing capacitor banks and regulators.
9. See also the Independent Professional Engineer and Investor-Owned Utilities recommendations sections under the General DIDF Reforms topic area.

Prioritization Metrics

10. To what extent did the IOU's 2019 DIDF filings present **clear explanations** about each factor used to establish the tier levels of prioritization? In what ways could the explanations about each factor be improved?
11. Should a common prioritization-metrics calculations **spreadsheet template** be used by all IOUs? For example:
    a. Should SCE's 2019 Excel **prioritization-metrics workbook** be used as the starting template?
    b. What improvements could be made to SCE's Excel workbook of prioritization metrics (*e.g.*, include the complete **Locational Net Benefit Analysis calculations** worksheets set in the same prioritizations workbook and ensure that each column has a descriptive heading that is explained in full in the text of the GNA/DDOR filing.)
12. In what ways could the prioritization metrics be revised to allow for **Grid Operator concerns** (qualitative assumptions) to be more transparently identified and incorporated such that project's like SCE's Alberhill Substation do not end up ranking high as deferral opportunities (*e.g.*, Tier 1) but with the IOU citing reasons other

[5] For examples, refer to the SCE Alberhill Substation and PG&E Estrella Substation projects in the respective 2019 GNA/DDOR filings.

than the metrics that a planned investment should still be ranked Tier 2, Tier 3, or in a separate Tier 4?

13. For planned investments that have both **capacity and reliability needs**, should the two needs be presented separately? Or, should they be presented both together and separately for comparison purposes when determining deferral opportunities?

14. Should the need date for the **Forecast Certainty** metric be replaced by the expected operational date of planned investments in the DDOR (*e.g.*, SCE Alberhill Substation and PG&E Estrella Substation projects). See also the Pre-Application Project section below.

15. How can the deferral opportunity prioritizations be modified to include more of the **value stack** to improve the cost effectiveness of DER procurements?

16. See also Attachment 2, Independent Professional Engineer Recommendations, under this topic area.

Pre-Application Projects

17. Should the **existing DIDF approach** be applied to Pre-Application Projects[6] to determine if the project or components of the project can be addressed by DERs prior the IOU filing a formal project application with the CPUC?
18. Assuming Pre-Application Projects continue to be included in the GNA/DDOR filings, are **additional DIDF guidelines** and other reforms needed? For example:
    a. Should the projects be identified in the GNA/DDOR filing but not prioritized into Tiers 1 to 3?

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[6] The term "pre-application project" refers to transmission and subtransmission projects with associated grid needs under CPUC jurisdiction that are expected to require review pursuant to GO 131-D. Projects filed under GO 131-D typically require review pursuant to the California Environmental Quality Act as well. The following three projects in the 2019 DIDF Cycle were identified that are already undergoing review pursuant to a GO 131-D application process before the CPUC: PG&E's Estrella Substation Project (Application (A.) 17-01-023), SCE's Alberhill Substation Project (A.09-09-022), and SCE's Mira Loma-Jefferson Line Project (A.15-12-007). No projects were identified that are expected to undergo review pursuant to GO 131-D in the future.

   b. Should the projects be identified in the GNA/DDOR filing and be prioritized into Tiers 1 to 3, but be exempt from the DIDF RFO process?
   c. Should the Tier 4 option be eliminated or further defined for the GNA/DDOR filings?
   d. Should it be further clarified that these projects will continue to be treated like any other GNA/DDOR planned investment in the annual DIDF cycles?

19. Should **regulatory and permitting costs** be included in the cost of planned investments identified in the GNA/DDOR filings? Should they also be itemized separately to allow for comparison to the cost of a DER deferral opportunity that may not require extensive permitting and environmental review?[7]

20. When a planned investment is expected to undergo review pursuant to GO 131-D, should project cost and the **Cost Effectiveness** metric be based on the filing information for the GO 131-D proceeding or the latest GRC information (*e.g.*, SCE Alberhill Substation cost is about $200 million per the GRC or about $500 million per SCE's GO 131-D filing details.)

IPE Review Process

21. What modifications to the IPE review process could improve DIDF outcomes? For example:
   a. Improve IOU **data organization** to increase efficiency of the IPE review process; and
   b. Improve IPE **verification and validation**, *e.g.*, increase the number of GNA/DDOR components to be verified and validated.

22. See Independent Professional Engineer recommendations under this topic area.

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[7] For the SCE Alberhill Substation Project, originally filed in 2009 under CPUC Application A.09-09-022, the design and permitting process has cost about $42 million dollars. Excluding land costs, which may be recovered through sale to a third party, SCE has incurred approximately $42 million of capital expenditures, including overhead costs, as of December 31, 2018, of which approximately $31 million may not be recoverable if the project is cancelled. Refer to the SCE 2018 Annual Report at pages 17 to 18, available here: http://www.annualreports.com/HostedData/AnnualReports/PDF/NYSE_EIX_2018.pdf.

Requests for Offers

23. What modifications to the DIDF Advice Letter filing and RFO launch/review process could improve DIDF outcomes? For example:
    a. Should a **no-regrets** concept for excess capacity procurements be considered to more fairly assess the Cost Effectiveness and Market Effectiveness of DERs in comparison to traditional, wired solutions and DERs?
    b. What **Competitive Solicitation Framework** reforms are needed to improve DIDF outcomes?
    c. Should **IOU ownership** of DERs be allowed in DIDF RFO procurement? This could occur in a variety of ways:
        i. All DIDF RFOs are **big tent procurements** with no restrictions on which entity can bid and own the DER resource. DER bids are evaluated on a level playing field;
        ii. IOU ownership is allowed, but IOUs do not bid on the RFOs. IOUs may select third-party owned or design-build-transfer projects; and
        iii. IOU ownership of all or part of a potential DER solution is allowed with third-party ownership of the remaining need.
    d. Should IOU **customer programs**, e.g., energy efficiency, augment or provide back up for competitive RFO-based procurements to help ensure DER deployment instead of traditional, wired solutions.[8]

24. How might the IOUs coordinate DIDF RFO solicitations and procurements with other DER procurements related to other CPUC proceedings, *e.g.*, **resource adequacy, energy efficiency, demand response**, **microgrids**, etc.?

[8] Refer to the results of SCE's 2013 Preferred Resources Pilot initiated to validate the ability of a portfolio of DERs to meet local-area reliability needs. SCE found, "DER sourcing and deployment can potentially be improved when both competitive solicitations and customer programs are part of the DER sourcing strategy. … Customer programs provided increased speed of delivery." SCE lists location-specific Energy Efficiency marketing and incentive programs as a key example, stating, "this approach enabled SCE to source 74 MW of DERs through customer programs—about 45% more than originally planned" (2019 SCE annual report at https://www.sce.com/sites/default/files/inline-files/2019_PRP_AnnualReport.pdf).

25. In what ways could **Net Energy Metering and Self-Generation Incentive Program** resources participate in the DIDF RFOs while meeting incrementality requirements?

Other Reform Ideas, Possibly Longer Term

The following comments and questions are provided for longer term consideration and may not be possible to address until after the 2020 DIDF cycle. Note that item numbering is continued from the list of questions in the main body of the Ruling.

26. Should a formal review and adoption of IOU **reliability standards** for the subtransmission and distribution systems occur (i.e., all grid components not subject to the NERC, WECC, and/or CAISO planning standards)? As a starting point, for example, refer to PG&E's *Guide for Planning Area Distribution Facilities*. It identifies distribution planning guidelines and criteria, forecasting processes including those for DERs, and includes a section on GNA/DDOR requirements. Compare the PG&E GNA/DDOR internal plans to Attachment A to the CPUC May 7, 2019 Ruling[9] that outlines GNA/DDOR requirements.
27. **IPE verification** that **reliability needs** identified in the GNA/DDOR filings for *distribution and subtransmission* components (i.e., non-CAISO jurisdictional) are reflective of an adopted standard and request a copy of the standard. Similarly, IPE verification that reliability needs related to the *transmission* system, if any, (i.e., CAISO jurisdictional) are reflective of an appropriate, adopted NERC, WECC, and/or CAISO transmission planning standard (e.g., Estrella Substation Project and the associated Cholame Substation and 70-kV N-1 reliability needs identified by PG&E).
28. Identify a select group of planned investments (**case studies**) from the GNA/DDOR filings for the IPE to investigate in greater detail.
29. In what ways would additional **coordination with other CPUC proceedings** improve DIDF outcomes (e.g., R.14-10-003 for Integrated Distributed Energy Resources, R.14-07-002 for Net Energy Metering, R.19-09-009 for Microgrids, R.17-07-007 for

[9] May 7, 2019 Administrative Law Judge's Ruling Modifying the Distribution Investment Deferral Framework.

Rule 21 reform, R.12-11-005 for Self-Generation Incentive Program, R.13-09-011 for Demand Response, R.13-11-005 for Energy Efficiency portfolios, R.18-04-019 for Climate Adaptation, R.18-10-007 for Wildfire Mitigation Plans, or others).

30. Please review the **behind-the-meter (BTM) propensity for adoption study** to be posted here https://www.cpuc.ca.gov/environment/info/horizonh2o/estrella/index.html in November/December 2019.[10] Comment on the potential value of similarly scoped study (i.e., case study) or larger-scale study of this kind[11] to help improve future DIDF outcomes. With respect to the incrementality discussions in this proceeding, note that BTM potential for adoption studies can be designed to assume that SGIP and NEM do not apply.

31. To what extent are the GNA/DDOR filings reflective of the **Grid Modernization Plans** filed by the IOUs in their respective GRCs, especially with respect to enabling the procurement and interconnection of cost-effective DERs empowered to provide a stack of benefits including, among other services, the deferral of traditional grid investments and mitigation of power shutoff risks related to heightened fire danger?

32. Should the GNA/DDOR filings identify all instances where:
    a. A **GO 131-D Advice Letter process** is expected to be required instead of a formal application filing for transmission or substation projects (i.e., a Notice of Construction or NOC filed with the CPUC)?[12]

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[10] Notification of the BTM propensity for adoption study's release is expected to be circulated to the R.14-08-013 service list. The study will be an appendix to the March 2019 Draft Alternatives Screening Report for the Estrella Substation and Paso Robles Area Reinforcement Project: https://www.cpuc.ca.gov/environment/info/horizonh2o/estrella/docs/2019-0325%20Estrella_ASR_PublicDraft.pdf. Refer to pages 3-58 to 3-59 of the March 2019 Screening Report.

[11] An example of a larger scale study is the "2025 California Demand Response Potential Study – Charting California's Demand Response Future: Final Report on Phase 2 Results" available at https://drrc.lbl.gov/publications/2025-california-demand-response. The study was based on electricity usage data from about 200,000 customer smart meters in California.

[12] Such projects are already identified in the IOU's quarterly filings pursuant to Assembly Bill (AB) 970 (and Decision D.06-09-003, and hence, the information, including, CPUC filing requirement, cost, in-service date, voltage/capacity, and location, among other details, are already being tracked and may be reasonable to include or cross-reference to the planned

b. The IOU anticipates that a public agency other than the CPUC will conduct the CEQA analysis for a DDOR planned investment to be filed with the CPUC pursuant to GO 131-D? According to GO 131-D, if another agency completes CEQA, the project may meet the GO 131-D criteria for a CPUC Advice Letter approval process instead of a formal application (i.e., a Certificate of Public Convenience and Necessity or a Permit to Construct).

Independent Professional Engineer Recommendations
General DIDF Reform Topics

A. This is the first year that the IOUs were required to report **segment-level needs**. The IOUs took different approaches. Instead of proving a list of all segments in the GNA whether they had a need or not, we recommend only listing segments that have needs to keep data sets manageable. The segment analyses were limited to the first three years of the GNA planning period, and thus, all segment needs were screened out due to the Timing Screen. The utilities should continue to perform these reviews and analysis at the circuit segment level as part of the GNA process such that future, streamlined procurement options can be considered that may differ from the current RFO process.
B. SDG&E's list of substation bank and **circuit level loading and deficiencies** provided in Appendix 2 (Tab "Ruling – Cir-Bank Capacity-Pub" in the Excel workbook) to their GNA/DDOR filing was prior to any newly identified phase balancing, transfer of loads or fixing of modeling discrepancies. It was not possible to know which of the bank/circuit level needs identified by the analysis were addressed using the above-mentioned actions without obtaining additional information from SDG&E. This is an important step in the GNA/DDOR process, since it screens out some needs that may otherwise have to be mitigated by installing new equipment. In the interest of transparency, SDG&E should provide the

investments identified in the DIDF. Although the AB 970 list is for transmission projects, some of the projects have significant distribution components (e.g., PG&E's Estrella Substation Project) that may be appropriate for deferral consideration. Cross checking with the AB 970 reports may also be important for general accuracy. For example, the SCE Alberhill Substation Project in-service date is listed as TBD in SCE's 10/1/19 AB 970 filing but 2024 in their 2019 GNA/DDOR filing.

reasons for removing any of these needs from the GNA in the GNA report filing.[13]

C. The lOUs calculate Locational Net Benefit Analysis (LNBA) values for candidate deferral projects in their DDORs using the **10-year period** as required by the CPUC May 7, 2019 Ruling. However, they do not apply a 10-year period for the calculation of these values (or ranges) in their GNAs. The LNBA values should align between the GNA and DDOR, hence, the GNAs values should apply the same planning periods as the DDORs.
D. All three IOUs proposed projects that include back-tie benefits/needs. We observed that these back-ties are often included in projects that also provide capacity service. The back-tie functions have been proposed to improve reliability and/or resiliency. We also observed that consideration of back-ties is becoming more important to the discussion of projects in the DIDF. In view of the increase in the number of projects with back-tie components or benefits we recommend that the IOUs provide **planning standards** documentation that show how they plan for back-ties, including how their planning process evaluates which back-ties are most important in improving customer reliability and how they determine their cost effectiveness. We recommend that the documentation also address planning for reliability and resiliency needs and benefits.

Prioritization Metrics

E. The consideration of planned investments with a combination of needs (e.g., capacity, reliability, and/or resiliency) should include an evaluation of how the **needs could be segregated** in some cases.[14]
F. SCE transitioned to using more **quantitative metrics** in their prioritization process for their 2019 GNA/DDOR filing. Each utility should follow this approach to add additional transparency and help stakeholders understand the basis for project prioritization such that meaningful feedback can be provided. The IOUs should apply the same prioritization process, as much as possible, and strive to use quantified metrics. The IOUs, in this effort, should review the detailed recommendations provided by the IPE in their respective Reports and work together, for example, in a

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[13] See also other issues of this type in the recommendations for SDG&E, IPE report, Section 2.5.

[14] Examples of projects where this was an important consideration in this year's DIDF cycle are PG&E's Estrella Project and SCE's Alberhill Project.

workshop to consider the IPE recommendations regarding metrics such as the use of an LNBA/MWh-day[15] metric.

G. Key assumptions such as discount rate, revenue requirement multiplier, inflation assumptions, O&M factor, and book life are important for calculating **LNBA values**. The IOUs should tabulate these assumptions, as well as provide the sources/basis behind these assumptions in the 2020 GNA/DDOR filings. The IOUs contend that some of this information is confidential. We recommend that it be provided in the IOU confidential filings.
H. The IOUs should consider the impact of **value stacking** on the prioritization metrics and process and discuss modifying their approach for the next GNA/DDOR filings.
I. We observe the importance of key assumptions such as discount rate, revenue requirement multiplier, inflation assumptions, O&M factor and book life on the LNBA values. We recommend that the utilities tabulate the assumptions they used in the LNBA model, as well as provide the sources/basis behind these assumptions in future GNA/DDOR reports.
J. The **Cost Effectiveness** metric should be given due consideration in the overall prioritization process as a threshold metric in that a DER solution needs to be cost effective to be successful in the bidding process, first and foremost.
K. SCE's implementation of the **Cost Effectiveness** metric has the potential for one component to dominate the other. The LNBA/kW, for example, can dominate the score, giving certain projects a higher overall score than may be warranted when considering that the LNBA/MWhr-year metric is the better of the two SCE metrics per the IPE's report recommendation (see SCE Alessandro Substation Project example and associated IPE review).
L. We appreciated SCE's effort to develop prioritization metrics and LNBA **calculations workbooks**. The other IOUs should consider adopting these templates for the 2020 DIDF cycle.
M. One improvement for SCE's approach is the development of a table to guide **Forecast Certainty** metric scorings for the Likelihood of a Project component because the concept of project certainty is somewhat subjective. The table of guidelines would clarify factors that could delay or accelerate project need. Another potential improvement in SCE's GNA/DDOR filing, is to review the design of the Year of Need and

[15] The IPE indicated in its reports that it believes this metric is the best of the cost-effective metrics in use. Reasoning is provided in the IPE reports.

Likelihood of project components of this metric to ensure one does not inadvertently dominate or override the other component.

N. SCE indicated that the Technology Neutral Pro Forma Agreement requires Day Ahead (DA) dispatch of DERs. For projects that have real time needs (event driven) this would require that they be dispatched every day that the event cold occur. This requirement will tend to make DER solutions more expensive and thus less attractive projects for developers. The IOUs should reconsider the **Day Ahead** dispatch requirements such that event driven DER projects are amendable to developer bidding. In general, the number of events experienced in an IOU service territory is low (i.e., five or less in any given year). This Day Ahead reliability requirement not only makes DER solutions less desirable to developers, it also impacts the calculation of prioritization metrics.

Pre-Application Projects

O. DPAG stakeholders would benefit from additional information about the three Pre-Application Projects identified in the 2019 DIDF cycle. The three projects might benefit from further review for Tier 1 consideration that is put on a different timeline than other Tier 1 proposals expected from the IOUs on November 15, 2019.

IPE Review Process

P. IOUs should engage the IPE earlier in the DIDF cycle to allow the work necessary for **verification and validation** to be properly planned and implemented. IPE engagement in May, for example, when IOUs prepare for the Distribution Forecasting Working Group workshop would be a logical timeframe. This workshop provides a forum to vet all the forecasting methodology, input data, and assumptions with stakeholders. Detailed discussions at this time would provide more time for IOUs to prepare their verification and validation walk-throughs with the IPE.

Q. Any **additional local, known loads** should be shared with the California Energy Commission's (CEC) for consideration in the Integrated Energy Policy Report (IEPR) data (e.g., SCE's local known growth projects, or LGPs) if they are not already being shared. Furthermore, the IOUs should include in their GNA/DDOR filings a comparison of the net load forecasts in their previous GNA/DDOR with the actual weather adjusted net load for each circuit for candidate deferral projects. Some IOUs perform such a check already. This will likely be valuable to many stakeholders including the CEC.

R. The GNAs should provide further information regarding **DER-driven needs**, e.g., the required equipment and steps taken by the IOU to develop the non-DER solution as well as the steps planned or taken by the IOU to upgrade monitoring and control systems to allow DERs to meet such needs in the future.
S. The CPUC should work with the **CEC** to ensure that all CEC IEPR data needed by the utilities for GNA/DDOR development be made available to the public so that stakeholders can have access to the data that the IOUs are using in their load forecasting and disaggregation processes.

Requests for Offers

– None identified by IPE.

Investor-Owned Utility Recommendations

General DIDF Reform Topics

a. PG&E: **Customer Count and LNBA information** should only be required for the Candidate Deferral Opportunities (rather than for all Planned Investments), as the purpose of this information is to evaluate the feasibility of DER deferral and it is a significant undertaking to provide this information for all Planned Investments.
b. SCE: Provide **customer composition details** for Candidate Deferral Opportunities only (rather than for all Planned Investments).
c. PG&E: Viability of DER projects that rely on **additional revenue streams** should be further considered, especially if the DER project has not been studied for interconnection and requires charging (acts as a load) from the overloaded circuit.
d. PG&E: **Line sections should be excluded** from future DIDF cycles, as assessing line section needs and documenting the line section Planned Investments requires extensive effort, while few, if any, are likely to be viable Candidate Deferral Opportunities due to the near-term identification of the need, the uncertainty of the long term forecast for line sections, the relatively smaller amount of customers for which to potentially market DERs, and the relatively smaller cost of the traditional mitigation.
e. SCE: Submit GNA/DDOR filings on August 15 annually and publish this content on the IOU **online maps** later, by August 31 annually, because of the addition time required to publish this information in the online portal format, including testing portal functionality after the annual update.

f. SCE: Renewed request regarding the accounting of **contingency planning costs**.[16]

Prioritization Metrics

– None identified by IOUs.

Pre-Application Projects

g. SCE: **Licensing projects** (i.e., projects requiring a GO 131-D application) do not fit within the established DIDF process and should be excluded from the DIDF's Candidate Deferral Project shortlist. SCE proposes, instead that the IOUs evaluate potential DER solutions as part of an internal alternatives analysis and solicitation process prior to filing their GO 131-D project application with the CPUC.

IPE Review Process

– None identified by IOUs.

Requests for Offers

h. PG&E: Renewed request to condense the **DPAG schedule** and generally streamline the DIDF regulatory process to allow for more time for the bidding and RFO process.[17]

i. SCE: Renewed request to **streamline the Competitive Sourcing Framework**.[18]

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16 See May 7, 2019 Administrative Law Judge's Ruling Modifying the Distribution Investment Deferral Framework Process at pages 12 to 13 and Appendix F to August 23, 2019 Amended Reports of Southern California Edison Company (U 338-E) of Its 2019 Grid Needs Assessment and 2019 Distribution Deferral Opportunity Report at pages 3 to 4.

17 PG&E March 2019 Opening Comments on February 25, 2019 Administrative Law Judge's Ruling Requesting Answers to Questions to Improve the Distribution Investment Deferral Framework Process, at pages 3 to 5.

18 See Joint IOU comments on R.14-10-003 Amended Scoping Memo of Assigned Commissioner and Joint Ruling with Administrative Law Judge in the Integrated Distributed Energy Resources Proceeding, March 29, 2018, at pages 8 to 11; SCE Utility Regulatory Incentive Mechanism Pilot Report, R.14-10-003, February 4, 2019, at page 15; Comments of Southern California Edison Company (U 338-E) on the Administrative Law Judge's Ruling Requesting Answers to Questions to Improve the Distribution Investment Deferral Framework, March 19, 2019, at page 15.

(End of Attachment B)

ATTACHMENT C

Attachment C
Independent Evaluator (IE) Scope of Work for DIDF Implementation

Term

- January 1 each year to July 31 the following year with the term subject to update by Energy Division if needed to support each DIDF cycle.

Pre-DPAG Period

- Participate in DPAG planning activities as directed by Energy Division, such as RFO reform planning and associated working groups. Among the reforms, consider the impact of IOU ownership and potential need for controls to level the playing field.
- Present findings from past IE RFO reviews and reports to the DPAG as directed by Energy Division.
- Other technical support assignments as defined by Energy Division to sufficiently plan for solicitation activities, clarify IE findings from prior DIDF cycles, and keep the IE informed about projects expected to be included in RFOs.

DPAG Period

- Participate in workshops and meetings during the DPAG period as requested by Energy Division.
- Prepare and deliver DPAG presentations or handouts as requested by Energy Division.
- Other technical support assignments as defined by Energy Division to ensure the DPAG process is successfully completed and RFO processes adequately planned.

Post-DPAG Period

- Assist the IOUs with the development, design and review of RFOs. Promptly submitting any recommendations consistent with the objective of ensuring a competitive, open and transparent process, and to ensure that the overall scope of the solicitation process is appropriate. Review all bid evaluation criteria and methodologies.
- Support Energy Division's in-depth review of RFO materials and RFO outcomes. Among the outcomes, consider and make recommendations about the impact of IOU ownership and potential need for controls to level the playing field.
- IE will be provided access to IOU personnel, modeling and evaluation tools, data, meeting documentation, and communications between the IOU, bidders, and potential bidders to credibly evaluate the bid valuation and selection processes. IE will be enabled to participate in IOU internal meetings and correspondence relating to the offer evaluation, such as draft offers, term sheets and contracts, regarding the contract negotiations with each of the counterparties.

- Monitor the solicitation contracting processes and all communications and/or negotiations between PG&E and counterparties and ensure the solicitation objectives are accomplished as outlined in the protocol approved by Energy Division.
- Promptly submit recommendations to Energy Division and the IOU to ensure no bidder has an information advantage and that all bidders receive access to relevant communications in a non-discriminatory manner. Among the recommendations should be those concerning the precise definition of products sought as well as price, non-price, quantitative, and qualitative evaluation criteria.
- Energy Division may request that the IE independently review and perform a parallel evaluation of sufficient rigor to validate the IOU's evaluation and selection process and outcomes and verify all offers were fairly and appropriately evaluated.
- Develop ***IE DIDF RFO Reports***. Report on RFO outcomes using the reporting template approved by Energy Division for DIDF RFO purposes. IE may be asked to develop a DIDF-specific or updated template.
- Develop a single ***IE Post-RFO Comparison Report***. If multiple IEs were employed by the IOUs, coordination among the IEs (as facilitated by Energy Division and possibly the IPE) may be required to complete the report. IE may be asked to develop a report template.
- Coordinate with and support the Independent Professional Engineer (IPE) with development of the IPE Post-DPAG Report as needed to avoid overlap and discuss DIDF reforms.
- Submit the draft reports to Energy Division for review and (if necessary) to the IOUs to check for confidential information that may be included.
- Submit the final reports to Energy Division and prepare public versions as needed.
- Support Energy Division with their review of DIDF reform comments, including comments on any IE tasks.
- Provide technical support and presentations as requested by Energy Division or as requested by the IOU being sure to include Energy Division on any IOU requested activities.
- Coordinate with the IPE to receive technical support at the discretion of Energy Division.
- Other technical support assignments as defined by Energy Division to evaluate RFO effectiveness and develop and evaluate potential DIDF reforms.

Improper Influence

- If the IE perceives that they are the target of any attempt to improperly influence, pressure, or otherwise affect their findings, whether by the IOU, any RFO participant, or any other party whatsoever, IE is obligated to immediately inform

Energy Division and the IOU's ethics officer and/or auditors or regulatory compliance personnel as applicable to the IOU.

Description of IE DIDF Deliverables

1. ***IE DIDF RFO Reports:*** a report for each IOU that evaluates the fairness of the DIDF RFOs upon RFO conclusion and any other aspects of the IE scope of work and as requested by Energy Division. Assess whether the solicitation processes were open, transparent and fair, and whether any bidder received material information that gave them a competitive advantage or disadvantage relative to other bidders. Assess whether the IOU's evaluation criteria and methodologies were reasonable and appropriate and applied in a fair and non-discriminatory manner for all offers received. Provide recommendations for future RFO improvements Completion dates to be identified by Energy Division in coordination with the IE.
2. ***IE Post-RFO Comparison Report:*** a single report prepared annually covering all three IOUs that compares their RFO materials, evaluates compliance, compares RFO outcomes, tracks RFO outcomes over time, and makes recommendations for best practices, standardization, RFO improvements, and associated DIDF reforms. Completion date and final contents of the report to be identified by Energy Division in coordination with the IE.

(End of Attachment C)