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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 (Filed August 14, 2014)
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 (Filed July 1, 2015)
And Related Matters.	Application 15-07-007 Application 15-07-008

ADMINISTRATIVE LAW JUDGE'S RULING REQUESTING ANSWERS TO STAKEHOLDER QUESTIONS SET FORTH IN THE ENERGY DIVISION STAFF PROPOSAL ON A DISTRIBUTION INVESTMENT DEFERRAL FRAMEWORK

Appended to this Administrative Law Judge's Ruling as Attachment A is the Commission's *Energy Division Staff Proposal on a Distribution Investment Deferral Framework* (*Staff Proposal*), which has been prepared in connection with the October 21, 2016 *Assigned Commissioner's Ruling on Track 3 Issues*, specifically

Track 3, Sub-track 3 of this proceeding. The *Staff Proposal* contains a number of stakeholder questions pertaining to the establishment of a Distribution Investment Deferral Framework, a primary component of a proposed annual Distribution Resource Planning process. Besides responding to these questions, parties are invited to comment generally on the *Staff Proposal*.

Stakeholders shall have until July 31, 2017 to serve and file their opening comments, which shall not exceed 30 pages (inclusive of exhibits).

Stakeholders shall have until August 11, 2017 to serve and file their reply comments, which shall not exceed 15 pages (inclusive of exhibits).

IT IS SO RULED.

Dated June 30, 2017, at San Francisco, California.

/s/ ROBERT M. MASON III
Robert M. Mason III
Administrative Law Judge

ATTACHMENT A

California Public Utilities Commission

Energy Division Staff Proposal on a Distribution Investment Deferral Framework

Distribution Resources Plan

Rulemaking 14-08-013

Marc Monbouquette

June 2017

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Terminology and Acronym Glossary:

ACR	Assigned Commissioner's Ruling
CAISO	California Independent System Operator
CEC	California Energy Commission
Commission	California Public Utilities Commission
CSF	Competitive Solicitation Framework
CVR	Conservation Voltage Reduction
D.	Decision
Deferral Framework	Distribution Investment Deferral Framework
DER	Distributed Energy Resource
DPA	Distribution Planning Area
DPAG	Distribution Planning Advisory Group
DRP	Distribution Resources Plan Proceeding / new Distribution Resources Planning Process
GNA	Grid Needs Assessment
GRC	General Rate Case
ICA	Integration Capacity Analysis
IDER	Integration of Distributed Energy Resources Proceeding
IEPR	Integrated Energy Policy Report
IOU	Investor-Owned Utility
IPE	Independent Professional Engineer
kVA	Kilovolt-Amp
kWh	Kilowatt-Hour
LNBA	Locational Net Benefits Analysis
ORA	Office of Ratepayer Advocates
PG&E	Pacific Gas and Electric Company
P.U.	Public Utility
R.	Rulemaking
RFO	Request for Offers

SCE	Southern California Edison Company
SDG&E	San Diego Gas and Electric Company
Staff	Energy Division Staff
TURN	The Utility Reform Network
VVO	Voltage/VAR Optimization

1. Introduction

The Energy Division Staff (Staff) of the California Public Utilities Commission (Commission) has prepared this proposal in order to build the record in support of an eventual Proposed Decision establishing an ongoing Distribution Investment Deferral Framework (Deferral Framework) to occur within the investor-owned utilities' (IOUs) annual distribution planning process. The Deferral Framework builds upon the Competitive Solicitation Framework (CSF) and Incentives Pilot developed in the Integration of Distributed Energy Resources (IDER) proceeding[1] to establish 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 in the IOUs' distribution systems.

The Deferral Framework will enable DERs to be strategically deployed in optimal locations in order to provide grid services and realize net ratepayer benefits. As such, the Deferral Framework works in part to achieve the objectives of Public Utilities (P.U.) Code §769(b)(2), "Propose or identify standard tariffs, contracts, or other mechanisms for the deployment of cost-effective distributed resources that satisfy distribution planning objectives," and §769(b)(4), "Identify any additional utility spending necessary to integrate cost-effective distributed resources into distribution planning consistent with the goals of yielding net benefits to ratepayers."

The Deferral Framework and Grid Modernization Investment Framework, which is under consideration in Track 3 Sub-track 2 of the Distribution Resource Plan (DRP) proceeding, introduce a new focus on cost-effective DER integration to the existing distribution planning and investment processes through the establishment of new, recurring IOU deliverables, stakeholder review processes, and Commission procedural activities. As discussed in further detail below, Staff envisions a new IOU deliverable referred to as the Grid Needs Assessment (GNA) to result from the annual planning process. The GNA will present a characterization of grid needs, planned investments, and candidate distribution deferral opportunities across the IOUs' service territories based on the existing planning process and new DRP planning tools such as DER growth scenarios and the Integration Capacity Analysis (ICA).[2] The grid needs and candidate deferral projects presented in the GNA also serve as the main inputs into the Locational Net Benefits Analysis (LNBA),[3] and provide the foundation of several other

[1] Adopted by Decision (D.)16-12-036 in Rulemaking (R.)14-10-003.

[2] The ICA, under development in DRP Track 1, quantifies the available hosting capacity for additional load and generation on the IOUs' distribution circuits.

[3] The LNBA, under development in DRP Track 1, calculates the estimated value of DER deployment at specific locations in the IOUs' distribution systems.

DRP use cases, including informing proactive Grid Modernization investments[4] to accommodate autonomous growth of DERs.

As proposed, the IOUs, stakeholders, and Commission staff will then work collaboratively in a Distribution Planning Advisory Group (DPAG) to review the GNA and recommend for approval a final list of distribution deferral opportunities that should be solicited via the CSF. Over time, the specific functions of the DPAG can be honed to meet the oversight and advisory needs of DER-related planning processes and sourcing mechanisms as they evolve.

The IOUs have heretofore conducted the annual planning process with little to no Commission or stakeholder review or input, aside from the development of system-level forecasts in the California Energy Commission's (CEC) Integrated Energy Policy Report (IEPR) that serve as primary inputs to the planning process. Instead, the only visibility into location-specific load growth assumptions and grid need determinations has come through General Rate Case (GRC) testimony that lays out the IOUs' justification for proposed investments. As such, the Deferral Framework and Grid Modernization Framework provide enhanced opportunities for the Commission and stakeholders to review the assumptions and results of the annual planning process while establishing new DER integration objectives that help accomplish state climate and energy goals and realize ratepayer benefits.

1.1. Legislative and Procedural Background

Assembly Bill 327 (Perea, 2013) codified P.U. Code §769, which requires the IOUs to submit distribution resources plan proposals that identify optimal locations for the deployment of DERs that result in net ratepayer benefits. In response, the Commission initiated the Distribution Resources Plan (DRP) proceeding (R.14-08-013) to evaluate those proposals consistent with the high-level goals of:

- Modernizing the electric distribution system to accommodate two-way flows of energy and energy services throughout the IOUs' networks;
- Enabling customer choice of new technologies and services that reduce emissions and improve reliability in a cost efficient manner; and

[4] The Grid Modernization Investment Framework, under development in DRP Track 3 Sub-track 2, aims to establish an ongoing framework whereby the IOUs propose proactive investments in grid modernization technologies in order to better integrate increasing penetrations of DERs into distribution planning and operations. The Commission recently released a staff proposal exploring numerous considerations related to the establishment of a Grid Modernization Investment Framework:
http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M186/K580/186580403.PDF

- Animating opportunities for DERs to realize benefits through the provision of grid services.[5]

The original DRP Scoping Memo divided consideration of the DRP proposals into three tracks: 1) Methodological Issues; 2) Demonstration and Pilot Projects; and 3) Policy Issues.[6] This Deferral Framework staff proposal is a main component of DRP Track 3 Sub-track 3, which was scoped by the October 21, 2016 *Assigned Commissioner's Ruling on Track 3 Issues* (Track 3 ACR)[7] to include the following scoping issues from a list of potential Track 3 scoping issues in the original DRP Scoping Memo:[8]

- Distribution Investment Deferral Framework[9];
- Whether and when to require periodic updates to utility DRPs;
- Relationship to utility GRCs; and
- Integration of DRPs into utility distribution infrastructure planning and investment

The Track 3 ACR goes on to define the specific outcomes of Sub-track 3 as:

- Establishment of a process to identify opportunities for DERs to defer or avoid traditional distribution infrastructure projects;
- Establishment of a process for utilities to seek authorization and cost recovery for DERs sourcing to enable deferral or avoidance of traditional investments; and
- Consideration of a process to ensure that the savings from deferred or avoided distribution investments are accurately reflected in concurrent or subsequent GRC filings.

The Commission hosted a Deferral Framework workshop on December 12, 2016 for Commission staff, IOUs, and stakeholders to discuss a number of issues related to these outcomes. Specifically, workshop discussions were scoped around the following objectives:

[5] *Assigned Commissioner's Ruling on Guidance for Public Utilities Code Section 769 – Distribution Resource Planning*, February 6, 2015, p. 3.

[6] *Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge, Including Deconsolidation of Certain Proceedings and a Different Consolidation of Other Proceedings*, January 27, 2016, p. 5.

[7] Track 3 ACR, p. 7.

[8] DRP Scoping Memo, January 27, 2016, pp. 10-12

[9] The original DRP Scoping Memo (filed January 27, 2016) included, as a potential scoping item for Track 3, "Grid modernization investment/deferral frameworks." The Track 3 ACR bifurcated this item in setting the scope of Track 3 Sub-track 2, regarding a Grid Modernization Investment Framework, and Track 3 Sub-track 3, regarding a Distribution Investment Deferral Framework.

1. Establish a common understanding of how distribution infrastructure planning and cost recovery occurs today;
2. Explore how these existing processes can be modified to incorporate a framework for evaluating opportunities for DERs to defer or avoid traditional distribution system investments;
3. Discuss relevant considerations for a future planning process and Deferral Framework that will inform a Deferral Framework Staff Proposal.

This staff proposal in part reflects the IOU and stakeholder perspectives expressed at the workshop, and also incorporates learnings from the IDER Incentives Pilot. The proposal covers: the goals of the DRP proceeding regarding the integration of cost-effective DERs into distribution planning and operations; existing planning and investment activities; and new deliverables and stakeholder review processes that incorporate distribution investment deferrals into existing planning and investment processes. Parties are invited to comment on the questions posed throughout the proposal pertaining to certain aspects of the Deferral Framework, and may also comment on the proposal more generally.

1.2. Learnings from the IDER Incentives Pilot

D.16-12-036 in the IDER proceeding (R.14-10-003) adopted a Competitive Solicitation Framework (CSF) to procure DERs to realize distribution investment deferrals. The CSF was established with the following characteristics:

- **Technology-neutral** DER solicitations;
- **Initially, four distribution services** that can be solicited from DER projects:
    1. Distribution Capacity;
    2. Voltage Support;
    3. Reliability (Back-Tie);
    4. Resiliency (Microgrid);
- A **four percent incentive** on annual payments to DER projects contracted through the CSF; and
- An **Incentives Pilot** in which the IOUs were ordered to select at least one and up to four distribution deferral projects, testing the ability of the four percent incentive to influence the IOUs to solicit DER non-wires alternatives to traditional capital investments.

In order to carry out the Incentives Pilot, D.16-12-036 established an interim Distribution Planning Advisory Group (DPAG) for the purposes of reviewing IOU-selected distribution deferral projects; required the IOUs to hire an Independent Professional Engineer (IPE) to advise the IOUs and the DPAG; allowed market participants to participate in the DPAG; and required development of contingency plans. The Incentives Pilot DPAG ran from March 2, 2017 to April 20, 2017, with pilot deferral projects due for submission by the IOUs on June 22, 2017.

The IDER Incentives Pilot offers tangible learnings that can be applied to the ongoing Deferral Framework. Notably, the IOUs were able to hone the initial deferral screening criteria and prioritization metrics beyond those presented at the December 12, 2016 Deferral Framework workshop. This Staff Proposal takes into consideration the IOUs' application of initial screening criteria and prioritization metrics in the IDER pilot as well as what was presented at the workshop in making recommendations for the ongoing Deferral Framework.

The IDER Incentives Pilot was also instrumental in highlighting a significant limitation of the CSF as a DER sourcing mechanism. Planned distribution projects must be forecasted at least three years in advance in order to be deferred by DERs sourced by a solicitation, due to the time required to select deferral opportunities, obtain regulatory approvals, launch a solicitation, and construct and interconnect a DER project through to commercial operation. The minimum three-year lead time effectively removed virtually all voltage-support projects from consideration in the IDER pilot, since they are typically planned to meet grid needs that appear zero-to-two years out. Such a deficiency points to the need for the IDER proceeding to consider streamlined DER sourcing mechanisms and regulatory approval processes. More importantly for this Staff Proposal, planning activities related to distribution deferrals must be able to characterize relatively shorter-term, smaller-magnitude grid needs in a way that streamlined DER sourcing mechanisms can effectively realize such deferral opportunities.

1.3. Context: The Existing Distribution Planning and Investment Processes

The IOUs have heretofore planned and constructed their electric distribution systems around the prevailing system architecture of centralized power stations and one-way power flows down to the end-use customer. The IOUs provided a high-level[10] overview of the annual planning process at the December 12, 2016 Deferral Framework

[10] It is noted that each IOU plans and invests in its distribution system according to company-specific standards and practices.

Workshop,[11] which is summarized below. The objective of the planning process is to examine the distribution system's ability to accommodate forecasted system conditions and select least-cost/best-fit engineering solutions to meet identified grid needs. The planning process begins in late summer/early autumn once system peak is measured and recorded and consists of the following four steps that occur over the course of seven to ten months:

1. **Develop Assumptions around load and DER growth**
   a. **Load forecast**: the IOUs start with system-level (top-down) load forecasts from the CEC's IEPR and develop a 1-in-10-year temperature-adjusted load forecast down to the Distribution Planning Area (DPA) and substation level based on historical loading, economic indicators, and temperature data. The DPA-level forecast is further disaggregated to substation banks and individual feeders using demographic and economic indicators and historical customer class kWh consumption data to forecast new customer class growth.
   b. **DER growth forecast[12]**: IOUs estimate projected DER growth through interconnection queues, rebates and incentive programs, economic and demographic factors, and the effects of building codes and standards. Existing and future DER interconnections are factored into feeder-level load shapes.
2. **Distribution Planning Assessment**: in this step, the IOUs assess historical system performance and project the system's future ability to maintain safety and reliability given load and DER growth forecasts, equipment ratings, voltage limits, etc.
3. **Distribution Grid Needs**: the IOUs compile grid needs related to thermal capacity, voltage and power quality, system protection, and safety and reliability based on the Distribution Planning Assessment. Grid needs are characterized by location, timing, magnitude (e.g., kVA), probability of occurrence, and conventional solutions that would alleviate the need. In general, the timing of a specific grid need corresponds to the system resolution at which the need exists: e.g., near-term (1-3 years) needs at the primary distribution line level; mid-term (3-5 years) needs at the substation transformer level; long-term (5-10 years) needs potentially requiring new substation construction.

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[11] Materials from the December 12, 2016 Deferral Framework workshop can be found at http://www.cpuc.ca.gov/drp_workshops/.

[12] Methods for developing locationally-granular forecasts for load and DER growth are under consideration in DRP Track 3 Sub-track 1.

4. **Evaluate Alternatives**: the IOUs identify and develop cost estimates for alternative solutions that can meet identified grid needs. The IOUs select solutions on a least cost/best fit basis, i.e., the solutions that are the most technically feasible at the lowest cost. In general, no- to low-cost solutions are first considered before capital projects are scoped out and evaluated.

   Implement Selected Alternatives: the IOUs then engineer, procure materials for, and construct the preferred solution, track project milestones, update the GIS asset database, and include the project as an assumption for the next planning cycle.

The IOUs request funds to finance planned distribution infrastructure projects identified in the annual planning process through the triennial GRC, a resource-intensive proceeding focused on setting an overall budget or revenue requirement that funds the IOUs' operations. However, such planned projects are only constructed if grid needs persist as forecasted. In some cases, IOUs repurpose approved GRC budgets to address changing grid conditions or spending priorities. Any unspent budgets contribute to the IOUs' earned rate of return.

The annual planning process, alongside the GRC, is one of the IOUs' core business functions, central to the goal of maintaining safe and reliable operations. Unlike the GRC, however, the planning process has heretofore been carried out by the IOUs according to internal practice and principles, without Commission or stakeholder review or input.

2. Proposed Annual Distribution Resource Planning (DRP) Process to Address P.U. Code §769

In this section, Staff proposes an ongoing regulatory framework to coordinate annual DER integration-related planning activities, referred to as the Distribution Resources Planning (DRP) process, that achieves the objectives of P.U. Code §769. The new DRP process builds on the steps in the IOUs' existing distribution planning process laid out above and establishes an annual procedural schedule for two of the main frameworks that make up the DRP process: the Deferral Framework and Grid Modernization Framework. The Deferral Framework and Grid Modernization Framework would entail new IOU deliverables, stakeholder processes, and Commission authorizations and would be closely coordinated to identify synergies, co-benefits, and co-dependencies that help realize net ratepayer benefits.

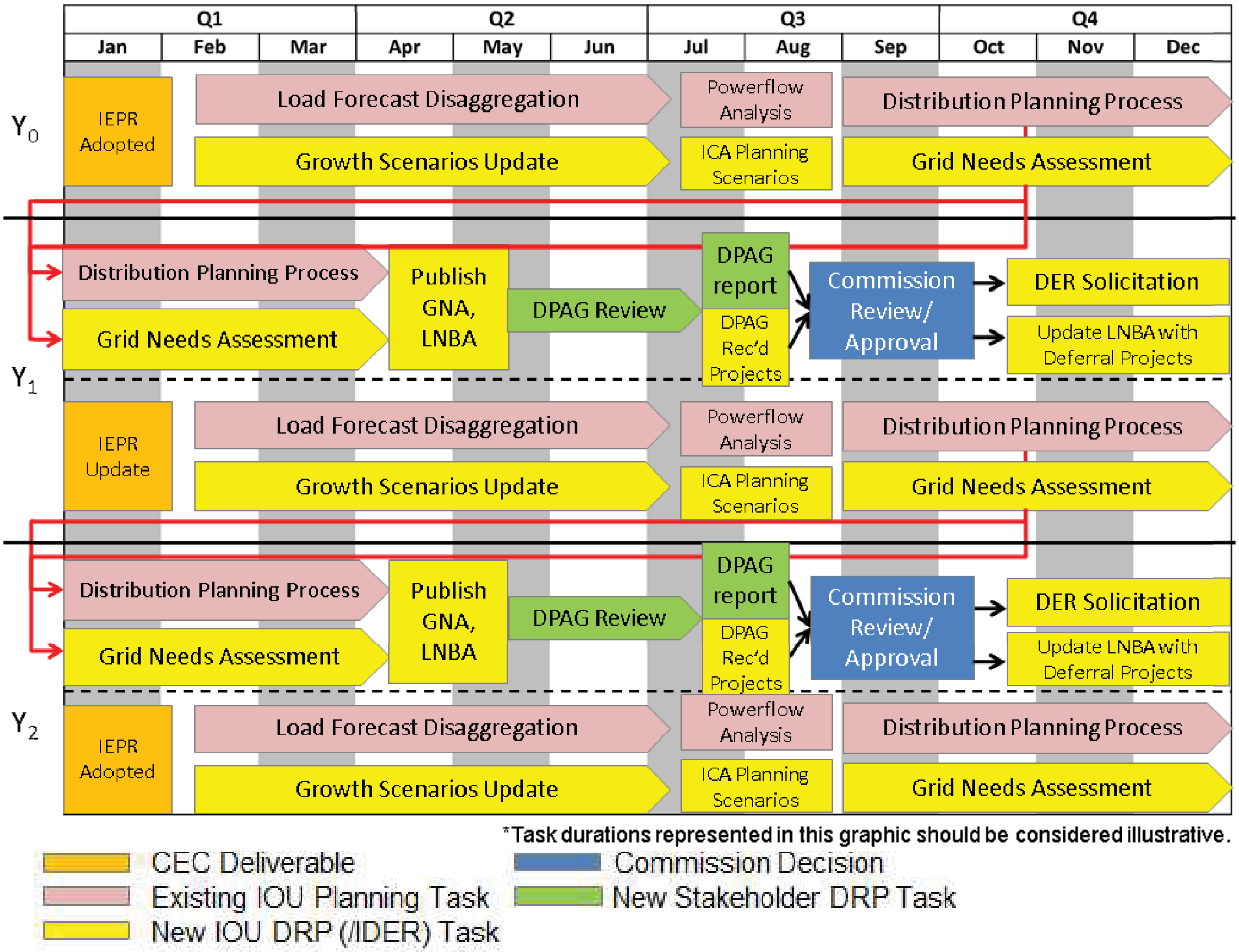
The annual DRP process with regards to the Deferral Framework would entail the following high-level steps, which are visualized in the proposed process flow in Figure 1:

1. Run power flow analyses and ICA planning scenarios using current load and DER growth forecast assumptions;
2. Complete distribution planning process with assistance from power flow analyses and ICA scenarios, while compiling grid needs, planned projects, and candidate deferral projects for presentation in the Grid Needs Assessment (GNA) and Locational Net Benefits Analysis (LNBA);
3. Submit and publish GNA showing grid needs, planned investments, and candidate deferral projects in online maps and downloadable datasets; update and publish LNBA with candidate deferral projects;
4. Launch DPAG to evaluate candidate deferral opportunities and planning process results documented in the GNA and LNBA; and
5. DPAG recommends final distribution deferral projects; IOUs request Commission approval to launch solicitation for selected projects through formal filing.

While Step 1 tasks are under consideration in parallel efforts in the DRP proceeding,[13] Steps 2 through 5 are described in the ensuing sections.

[13] DRP Track 1 focuses on developing ICA and LNBA methodologies, while DRP Track 3 Sub-track 1 focuses in part on developing DER growth scenarios for use in the annual planning process.

Figure 1. Existing Distribution Planning Process and Proposed Distribution Resources Planning Process specific to the Deferral Framework*



2.1. Grid Needs Assessment

Staff proposes a new IOU-developed deliverable called the Grid Needs Assessment (GNA) that documents the grid needs and planned capital investments that result from the annual planning process and serves as the primary input to the Deferral Framework and Grid Modernization Frameworks. From the list of all planned projects, the GNA would also present a list of candidate distribution deferral opportunities produced through an initial deferral screening process. This candidate shortlist provides the main focus of the DPAG, whose primary role would be to recommend distribution deferral projects for solicitation based on a review of planning process assumptions and results as presented in the GNA, a prioritization of candidate projects, and other factors.

The GNA would be submitted annually around April or May of each year at the completion of the planning process and would entail a formal filing at the Commission as well as digital components. Specifically, the filing would include descriptions of system-level and disaggregated forecasting assumptions and planning methodologies, while resulting grid needs, planned investments, and candidate deferral projects will be presented in online maps and tabulated in downloadable datasets. The GNA would also include the estimated avoided costs of candidate deferral projects, which may be confidential and considered market sensitive.

The GNA represents a significant development into collecting, presenting, and sharing data on the IOUs' planning and investment processes. While the GNA would be concerned solely with the distribution planning process, there exists the potential to compare data on grid needs and planned investments with requested and approved GRC budgets and actual distribution system investments. In this way, IOUs, stakeholders, and the Commission would be able to gain quantitative insights into how IOU spending patterns are influenced by changes in location-specific forecasts and emergent priorities.

Development of the GNA for the purposes of the Grid Modernization Framework, as well as guidance regarding the GNA generally, will be accomplished through parallel DRP Track 3 procedural activities.

Stakeholder Questions:

1. What procedural vehicle (e.g., Application, Motion, Advice Letter, Compliance Report) is best suited for the IOUs' GNA submissions? Does the GNA need to be entered into the record in order to be referenced in the selection of distribution deferral opportunities? Similarly, does the Commission need to acknowledge, approve, modify, or otherwise dispose of the GNA? If so, by which vehicle should this occur?
2. Referencing Figure 1, by which date should the GNA be submitted, such that the IOUs have sufficient time to complete the annual planning process, compile the relevant data, and allow for sufficient DPAG review? By which dates should other steps in the DRP process occur? (This topic is addressed further in Section 2.4.4)
3. How should the Commission set thresholds for the type and magnitude of grid needs and planned projects that are reported in the GNA? Should grid needs and planned projects only be reported for the four distribution services identified in the IDER Competitive Solicitation Framework,[14] and over a given magnitude?
4. How should grid needs and planned projects be characterized in the GNA? How is such information presented in the GRC, and how can that inform its presentation in

[14] The four distribution services adopted by D.16-12-036 (pp. 7-9) include: 1) distribution capacity; 2) voltage support; 3) reliability (back-tie); and 4) resiliency (microgrid).

the GNA? What information do the IOUs need to provide in order to articulate the distribution upgrades that could be technically deferred by DERs? How should data be formatted and presented in both downloadable datasets and online maps?

5. Are there any confidentiality or market sensitivity issues surrounding certain attributes of grid needs and/or planned projects?[15] How can access to such types of data best be handled?

6. How can the Commission verify that all grid needs and planned projects over the established thresholds are included in the GNA?

2.2. Deferral Screening

The GNA would present a candidate distribution deferral project shortlist by applying initial deferral screening criteria to the list of planned capital projects documented in the GNA. The candidate shortlist would then provide the main focus of consideration in the Distribution Planning Advisory Group (DPAG), whose main task would be to recommend deferral projects from the candidate shortlist that should immediately go out for solicitation.

Staff notes that P.U. Code §769 directs us to maximize net ratepayer benefits through strategic DER deployment. The main goal of the Deferral Framework should thus be to capture all potential deferral opportunities that carry a high likelihood of being cost-effective. As such, the initial deferral screening process should identify the planned projects for which: 1) DER alternatives can technically meet the underlying grid need; 2) DER alternatives can be deployed in time to meet the underlying grid need; 3) DER alternatives are highly likely to result in cost-effective deferrals; and 4) the underlying grid needs have a relatively high degree of certainty of materializing as forecast. Staff thus proposes adopting the screens in Table 1 to create the candidate deferral project shortlist presented in the annual GNA.

The IOUs and other parties proposed a number of deferral screens at the December 12, 2016 Deferral Framework workshop that could be applied to create the candidate deferral project shortlist:

[15] Potential types of market sensitive information identified by the IOUs are described in Section 2.4.1.

Table 1. Proposed initial deferral screens

Party	Illustrative Screens	Description
IOUs, ORA, SolarCity	Technical Screen	Determine whether DERs can meet the identified grid need • Based on the distribution grid services adopted in the IDER Competitive Solicitation Framework • Services may evolve as more knowledge and experience is gained
IOUs, SolarCity	Timing Screen	Determine whether a DER solution can be deployed in advance of the forecasted need date • Project type and complexity drive differing lead times
IOUs, ORA, SolarCity, TURN	Economic/Financial Screen	Planned projects that carry a high likelihood of resulting in a cost-effective deferral • Consider adopting a minimum deferral value threshold to ensure administration of the Request for Offers (RFO) is justified • In the future, this may also include a preliminary cost-effectiveness screen • ORA: Longer-duration deferrals, i.e., investments that can be deferred for a relatively longer period of time, should be prioritized over shorter-duration deferrals • TURN: Avoided projects should be prioritized over deferred projects; incremental services
TURN, ORA	Forecast Certainty	Grid needs/projects with a higher likelihood of materializing should be prioritized over those with a lower likelihood of materializing • Essentially a screen against high forecasting uncertainty • In general, grid needs that are nearer-term and/or driven by multiple customers are more certain than needs that are longer-term and/or driven by relatively few customers

The IOUs then provided further elaboration behind the technical and timing screens, reproduced here in Tables 2, 3, and 4. For the technical screen, the IOUs presented examples of system constraints that are or may be potentially deferrable by DER services (Table 2), as well as system constraints that cannot be deferred by DER services, for which conventional infrastructure solutions would be required (Table 3):

Table 2: Examples of deferrable distribution infrastructure projects[16]

Distribution Service	Can DER Service be provided at present?	Types of System Projects	Example Equipment
Distribution Capacity	Yes	Thermal Capacity Upgrade Projects	• Substation Transformers • Line conductors
Voltage/VAR Support	Yes	• Voltage/VAR Projects • Conservation Voltage Reduction (CVR) • Voltage/VAR Optimization (VVO)	• Capacitor banks • Load tap changers • Line voltage regulators • Line Conductors
Reliability (back-tie)	Yes	Capacity upgrade projects driven by outage contingencies	Incremental equipment associated with projects
Resiliency (microgrid)	No	Capacity upgrade projects driven by outage contingencies	Incremental equipment associated with projects

Table 3. System constraints that cannot be deferred by DERs

Types of System Projects	Explanation
Repair/Replacement of damaged/deteriorated infrastructure (e.g. electrical equipment, structural equipment)	Equipment necessary to support electrical service and safe operation of the electrical system for both load and DER
Non-capacity related Reliability (e.g. automation, fault detection, sectionalizing equipment)	DERs don't reduce outage duration by sectionalizing circuits or detecting faults
Operations and Maintenance (e.g. equipment testing/ inspections, managing vegetation and animals, etc.)	Function not provided by DERs
Emergency Preparation and Response	Short timeframe to replace/repair damaged equipment to restore electrical service

[16] Types of System Projects and Example Equipment listed in Table 2 are defined in a Technical Glossary included as Appendix A.

Types of System Projects	Explanation
Minimum infrastructure required to serve customers	Obligation to serve

For the timing screen, the IOUs illustrated the typical lead times associated with certain planned projects and how such lead times impact a project's deferability:

Table 4. Illustrative project lead times and deferability considerations

Timeframe	Example Project/Equipment Deferral	Deferral Opportunity / Approach
Very Short Term (0-1.5 years)	Needs discovered during operations that must be addressed prior to the next peak season	• Potentially insufficient time to source and deploy DERs through an RFO • Would require expedited (likely non-RFO) sourcing mechanisms and regulatory approval process[17]
Near Term (1.5 – 3 years)	• Small thermal capacity needs (e.g., line conductors, small transformers) • Voltage/VAR projects (e.g., distribution line capacitors, load tap changers, line voltage regulators)	• Limited lead time requires expedited solicitation (or other types of non-RFO sourcing mechanisms) and regulatory approval process • Due to smaller size and low risk conventional projects, DER solutions might not be cost-effective

[17] DER sourcing mechanisms are currently in scope in the IDER proceeding (R.14-10-003). To date, the only sourcing mechanism defined by the IDER proceeding is the Competitive Solicitation Framework, originally described in the *Competitive Solicitation Framework Working Group Final Report* filed August 1, 2016, and adopted in D.16-12-036. This Staff proposal defines the need for non-RFO DER sourcing mechanisms to capture distribution deferral opportunities with lead-times outside of the "goldilocks" range of three-to-four years. The RFO process is not able to source DERs to defer planned projects with required in-service dates of zero-to-two years out, due to a minimum two-to-three-year lead-time to launch a solicitation and construct and interconnect a DER project. We expect the IDER proceeding to next take up development of non-RFO sourcing mechanisms.

Timeframe	Example Project/Equipment Deferral	Deferral Opportunity / Approach
Intermediate Term **(4 – 5 years)**	• Large thermal capacity needs (e.g., line conductors, substation upgrades, new circuits) • Voltage/VAR projects (e.g., substation capacitors, load tap changers) • Reliability (back-tie) (e.g., line conductors, switches)	• Procure DER through RFO solicitations in areas with larger attribute requirements • Expedited regulatory approval may still be necessary • Implement low cost and/or "no regrets" types of DER sourcing mechanisms
Long Term **(6 – 10 years)**	Projects with long lead times or that require licensing activities (e.g., New Substations, New Sub-Transmission Lines)	• LNBA maps signal market participants where DERs may provide grid benefits • Proceed to RFO when need is reasonably certain. • Implement low cost and/or "no regrets" types of DER sourcing mechanisms.

For the IDER Incentives Pilot, the IOUs applied initial timing and technical screens to the planned projects in their Distribution Capital Plans. The timing screen removed projects with less than a three-year lead time due to an estimated 22 months required for DER construction, permitting, interconnection, and commercial operation following bid selection and contract approval.[18] The timing screen also removed projects with forecasted lead-times of five years and greater due to the relative uncertainty surrounding such longer-term grid needs. Besides this, PG&E screened out a potential Reliability (back-tie) deferral project due to its determination that the affected circuit serves a prohibitively large number of customers to pilot a DER non-wires alternative.

Stakeholder questions:

7. Should the screens in Table 1 be used for the initial deferral screening process, or should certain screens be added or removed? Explain.
8. Do you agree with the IOUs' further characterization of the technical and timing screens presented in Tables 2, 3, and 4? What can be added or modified?

[18] It should be noted that recent energy storage solicitations launched by Resolution E-4791 in response to the Aliso Canyon gas leak demonstrated the possibility of more expedited solicitation, contracting, and interconnection timelines.

- *For IOUs:* Explain your rationale for stating in Table 2 that resiliency needs cannot be presently met by microgrid projects, given that this was one of the four DER services adopted in D.16-12-036 (see Footnote 9).
- *For all parties:* How can aspects of the Deferral Framework or DER sourcing mechanisms under development in IDER be honed to address the illustrative timing constraints described in Table 4?

9. Do you believe a maximum customer penetration threshold criterion, such as that employed by PG&E in the IDER Incentives Pilot, is reasonable for use in the ongoing Deferral Framework? Explain.

2.3. Prioritization Metrics

As noted above, the requirements of P.U. Code §769 dictates that we capture all potential deferral opportunities that carry a high likelihood of being cost-effective. The initial deferral screening criteria are geared towards identifying all planned projects for which DER alternatives can be confidently expected to meet the underlying grid need and yield net ratepayer benefits. The DPAG would then be responsible for reviewing candidate deferral projects that result from the initial deferral screening process and recommending projects that should go immediately out for solicitation.

While the DPAG's recommendations should be first and foremost based on maximizing the number of cost-effective deferrals, they should also be driven by the need to yield successful deferrals. For instance, it would be imprudent for the DPAG to recommend a deferral project that would otherwise provide net ratepayer benefits, but is located in an area where the market for DER host customers is relatively low or non-existent. Such an opportunity would likely not result in a successful deferral and should thus not be recommended for solicitation.

Prioritization metrics can help to further characterize candidate deferral opportunities beyond the initial screening process and assist the DPAG in making informed, high-confidence recommendations for deferral opportunities that are likely to be successful. However, prioritization metrics should not be viewed as a vehicle for further "weeding out" or excluding candidate projects from consideration that can otherwise be cost-effectively deferred.

At the Deferral Framework workshop, the IOUs proposed the following project prioritization metrics:

Table 5. IOU-proposed prioritization metrics from Deferral Framework workshop

Metric	Description
Timing/Certainty	Nearer-term needs (within five years) that carry a relatively higher certainty of need are higher priority than longer-term needs (beyond five years) that carry a relatively lower certainty of need
Market/economic assessment	Assessment of a given electrical footprint's customer composition, based on market knowledge gained over time

For the IDER Incentives Pilot, the IOUs employed a number of additional prioritization criteria to characterize candidate deferral projects according to the certainty of the underlying grid need and the market opportunity for hosting DER solutions.

PG&E scored each candidate deferral project by a High/Low priority for a number of sub-metrics. Sub-metric scores were then aggregated into overall High, Medium, and Low scores for Certainty and Market metrics, and projects scoring high overall were selected to go to solicitation:

Table 6: PG&E prioritization metrics in the IDER Incentives Pilot

Metric	Sub-Metric	Relative Priority
Certainty	Number of customers causing need	Many: **high** Few: **low**
	Projected need (absolute and percent)	Large: **high** Small: **low**
	Timing of need	Near-term: **high** Long-term: **low**
Market	Number of customers causing need	Many: **high** Few: **low**
	Ratio of projected need to customers/load on circuit/bank	Small: **high** Large: **low**
	Timing of need	Long-term: **high** Near-term: **low**
Overall	If Certainty is majority **low**, overall is **low**	
	If Certainty is majority **medium**, overall is **medium**	
	If Certainty and Market are both **high**, overall is **high**	
	All other combinations are **medium**	

SCE scored candidate deferral projects by five equally-weighted metrics, ranking projects 1 – *n* according to the High/Low priority descriptions described below. Scores were then summed across the five metrics, and SCE selected relatively high-ranking projects for solicitation.

Table 7: SCE prioritization metrics in the IDER Incentives Pilot

Metric	High Priority	Low Priority
DER attribute requirements	**Less** DER services required	**More** DER services required
Project timing certainty	**Nearer-term** needs; **less** historical **volatility** with load growth driving project need and required in-service date	**Longer-term** needs; **more** historical **volatility** with load growth driving project need and required in-service date
Financial Assessment (capital project cost)	**Higher cost** of traditional capital project	**Lower cost** of traditional capital project
Market Assessment (customer composition)	**Broad base** of large customers contributing to peak load (requires engaging relatively fewer customers to meet distribution need)	**Minimal number** of large customers contributing to peak load, or **highly residential** customer base (requires engaging many customers to meet distribution need)
Distribution topology (number of customers)	Projects that solve substation needs → provides a **larger** number of customers to potentially enroll in DER programs	Projects that solve specific circuit needs → provides a **smaller** number of customers to potentially enroll in DER programs

SDG&E prioritized projects by the following metrics:

Table 8: SDG&E prioritization metrics in the IDER Incentives Pilot

Category	Description
Certainty	Weather factor adjustment
	Customer-specific development
	Customer growth
	Historical load
Market	Electrical characteristics

Category	Description
	Cost per MW
DER Options	Peak duration
	Customer profile mix
	Peak timeframe
	Existing DER profile
	Customer count

Staff proposes that SCE's IDER Incentives Pilot methodology be established for use by the DPAG in the ongoing Deferral Framework, due to its clearly-defined quantitative ranking methodology. Staff also recommends use of the LNBA methodology for use in the Financial Assessment metric, as it includes system-level values along with the project-specific capital cost in calculating the estimated value of candidate deferral projects.

Stakeholder questions:

10. Is SCE's prioritization methodology from the IDER pilot adequate for use by the DPAG in the ongoing Deferral Framework? What metrics, if any, should be added, removed, or modified?
11. Provide comments or recommendations on the need for further prioritization after the initial deferral screening process. How can the overall screening process, from initial deferral screening criteria through to prioritization, be modified and/or improved?

2.4. Distribution Planning Advisory Group

The Distribution Planning Advisory Group (DPAG) is proposed as a stakeholder-driven Commission advisory body whose primary objective is to review planning activities and recommend distribution deferral opportunities to go out for solicitation[19] that have a high likelihood of resulting in successful, cost-effective deferrals. The DPAG would recommend distribution deferral projects by first reviewing the candidate project shortlist presented in the GNA with regards to the assumptions, methods, and results of the planning process and the application of deferral screens, followed by application of prioritization metrics and further review. In its review of the GNA, the DPAG would also have the option of considering for deferral planned projects that did not make the candidate shortlist after the initial deferral screening process.

[19] In the future, the role of the DPAG may evolve to provide a broader review of distribution planning activities for the purposes of informing new DER sourcing mechanisms developed through the IDER proceeding.

To clarify, the DPAG would not be a decision-making body; instead, it would be charged with providing input into the final portfolio of distribution deferrals submitted for Commission approval via the process outlined below. To the extent that the DPAG serves an advisory role to the Commission, and depending on the exact facilitation arrangement between Staff and the Independent Professional Engineer (IPE) technical consultant, establishment of the DPAG could elicit certain considerations related to:

- The Bagley-Keene Open Meeting Act;
- Per diem or intervenor compensation for non-IOU DPAG participants; and
- Annual Reporting on Trusts and Entities Created by the CPUC, per AB 1338 (2008) and P.U. Code §910.4

2.4.1. DPAG Composition

Staff proposes that the DPAG consist of IOUs, Commission technical staff, stakeholders including ratepayer, environmental, community, and clean technology advocates, and an IPE technical consultant. Market participants such as DER project developers would be allowed to participate as discussed below.

- **Independent Professional Engineer:** The IPE would facilitate technical review of the GNA with regards to the assumptions and results of the annual planning process and the application of initial deferral screens. The IPE would be responsible for determining whether distribution deferral project cost estimates are reasonable, and verifies and approves the DER attributes needed to defer a given traditional capital project. Then, the IPE would assist in the recommendation of distribution deferral projects from the candidate deferral project shortlist that are proposed for solicitation. Finally, the IPE would be responsible for preparing a DPAG Report that reviews the DPAG's evaluation of candidate deferral opportunities and documents IOU and stakeholder feedback regarding the number and types of distribution deferral projects that were ultimately selected. This report would be submitted concurrently with the formal request for deferral project approval, as described in more detail in Section 2.4.2 below.[20]

  Consistent with the process adopted in D.16-12-036 for the IDER pilot, the IOUs would oversee the IPE selection process, pursuant to review and approval by the Commission.

[20] We note the need for the IPE's DPAG report to be filed with the IOUs' advice filings in order to inform the Commission's disposition of requested deferral projects, especially with regards to potential deferral projects that were not included in the consensus recommendation.

- **Market participants:** The potential inclusion of market participants such as DER project developers in the DPAG was a prominent point of contention between the IOUs and DER stakeholders at the Deferral Framework workshop. This is because the DPAG may be privy to potentially confidential, proprietary, or otherwise-market-sensitive information related to the annual planning process and selection of distribution deferral projects. As asserted by the IOUs at the workshop, types of market-sensitive information may include:
    - Actual costs of conventional distribution infrastructure projects under consideration for deferral;
    - Location- and/or customer-specific confidential forecasts of load and resources;
    - IOU proprietary projections and modeling outputs;
    - Precise technical calculations in determining which conventional projects can be deferred and for how long;
    - Technical and financial evaluation of DER technologies as alternatives to distribution investments;
    - Comparative cost of solutions including the cost of conventional infrastructure;
    - An assessment of DERs' effectiveness in providing distribution functions; and
    - Discussions regarding where, when, and how to pursue alternative solutions.

The concern with granting market participants access to market-sensitive information in the DPAG stems from the potential for engaged entities to gain competitive advantages and/or manipulate a DER solicitation. This most directly relates to the first item in the above list, "Actual costs of conventional distribution infrastructure projects under consideration for deferral," and the potential for a DER solicitation to be flooded with bids that come in right under the actual cost of the conventional project. D.16-12-036, which adopted the IDER Incentives Pilot, reflected this concern by excluding market participants from any DPAG discussions regarding market sensitive information established in D.06-06-066, especially the potential distribution costs that may be avoided by DERs. That decision also noted that future inclusion of market participants in distribution planning activities shall be determined in the DRP proceeding.[21]

On the other hand, DER parties in the IDER Incentives Pilot maintained that access to actual cost information is critical for enabling an effective and competitive DER marketplace. Primarily, DER market participants are concerned that significant resources could be wasted assembling bids and recruiting potential DER host customers if their bids ultimately come in above the actual avoided cost. Furthermore,

[21] D.16-12-036, p. 28.

DER market participants asserted that the diversity of DER technologies[22] eligible to respond to a distribution deferral RFO will ensure the competitiveness of distribution deferral RFOs despite being privy to the actual cost their bids must beat.

We agree that certain items in the above list could be construed as market-sensitive or confidential, while other items seem more open to interpretation. Staff believes that the DPAG could benefit from DER developers' insight into the capabilities of their products when discussing the technical feasibility of certain deferral opportunities. Therefore, Staff proposes that market participants be permitted in the DPAG.

Stakeholder questions:

12. Do you agree with Staff's proposal for the DPAG to consist of IOUs, Commission technical staff, advocates, DER market participants, and an IPE technical consultant? If not, what types of stakeholders should be included or excluded?
13. D.16-12-036 determined that the actual costs of conventional distribution projects should be treated as confidential information for the purposes of the IDER Incentives Pilot. Should the Commission apply this same determination to the ongoing Deferral Framework? Are there additional considerations or new information relevant to making this determination?
14. More broadly, which other types of information presented by the IOUs at the Deferral Framework workshop (reproduced above) can be reasonably construed as market sensitive and/or confidential? Please provide adequate justification and cite all relevant statutory language and/or Commission decisions.

2.4.2. DPAG Structure, Process, Recommendations, and Deliverables

A few options exist for how the DPAG is structured and arrives at its recommendations. The options for DPAG facilitation and oversight are as follows:

1. The IPE, in consultation with Staff, facilitates a consensus-building process within the DPAG to arrive at a final list of recommended deferral projects, collectively referred to as "DPAG Recommended Projects."
2. Staff facilitates a consensus-building process within the DPAG to arrive at a final list of recommended deferral projects, collectively referred to as "DPAG Recommended Projects," based on DPAG and IPE consultation.

[22] P.U. Code §769 (a): "For purposes of this section, 'distributed resources' means distributed renewable generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies."

Staff proposes that the DPAG be structured according to Option 1, wherein the IPE, in consultation with Staff, facilitates a consensus-building process to develop deferral project recommendations that are submitted by the IOUs for Commission approval in a Tier 3 Advice Letter. This option is preferred in order to leverage the technical expertise of the IPE in facilitating the consensus-building process within the DPAG.

Furthermore, Staff proposes that the IOUs be required to file a Tier 3 advice letter requesting Commission approval of DPAG Recommended Projects and authorization to launch RFOs, accompanied by: preliminary contingency plans (discussed in Section 2.4.3 below); the actual value of deferred or avoided investments (which may be considered confidential and market sensitive); and a DPAG Report prepared by the IPE, which, amongst the things discussed in Section 2.4.1 above, would detail the reasons for which certain candidate deferral projects did not achieve DPAG consensus. The Tier 3 advice letter vehicle likely allows for the most streamlined regulatory approval process, and was the filing type ordered by D.16-12-036 for the same purpose in the IDER Incentives Pilot.

Over time, the Commission may wish to further streamline this process and allow for a Tier 2 advice letter filing instead. Staff thus recommends a process whereby the Commission may, at its discretion, change the advice letter tier designation for future filings, should it find that a more streamlined regulatory approval process is reasonable and justified going forward. Such a tier designation change would be enacted through the resolution disposing of a given year's Tier 3 advice letter requesting approval of DPAG Recommended Projects.

Stakeholder questions:

15. Which of the two options detailed above enables the DPAG to most effectively carry out its charge of recommending successful distribution deferral projects for solicitation? Are modifications needed to certain elements of these options, or is there a preferred option that is not mentioned here? Do you foresee any issues related to establishing the DPAG as an "Entity or program established by the Commission by decision" (per P.U. Code §910.4)?
16. Between the adopted vehicle for proposing DPAG Recommended Projects and the IPE's DPAG Report, how can candidate deferral projects that do not achieve consensus be best documented for Commission review and disposition?

2.4.3. Contingency Planning

The IOUs, in consultation with the DPAG, would be responsible for developing contingency plans for DPAG Recommended Projects for which DER alternatives do not materialize as anticipated. Contingency planning entails escalating degrees of design, cost estimation, procurement, and construction of traditional infrastructure solutions that can be implemented as the DER alternative progresses through stages of solicitation, construction, and operation.

The IOUs and DPAG must plan to mitigate the following contingencies associated with various stages of DER project development and operation:

Table 9. Distribution deferral project contingencies and potential mitigations

Stage	Contingency	Potential Mitigation(s)
Solicitation	The market fails to provide a cost-effective DER solution that can deliver the required attributes to meet the identified grid need	• Implement traditional capital project
Construction	A contracted DER project or portfolio fails to meet certain construction milestones	• Contract with solicitation runners-up to develop expedited DER deployment • Implement traditional capital project
Operation	A DER project or portfolio fails to provide the contracted services when dispatched, potentially jeopardizing grid safety and reliability	• Emergency grid operations, switching, and/or traditional capital project implementation • Standing contract with DER developer(s) for expedited turn-key DER deployment

Whichever filing mechanism is adopted for the IOUs to request Commission approval of DPAG Recommended Projects should include high-level contingency plans for each stage of project deployment.

Stakeholder questions:

17. To what degree should the Commission prescribe the types of potential mitigations for contingencies at various stages of DER project development? Or, should such mitigations be determined by the DPAG on a case-by-case basis, depending on the specific types and magnitudes of grid needs that are being deferred?
18. To what level of detail should the IOUs scope out contingency plans for specific distribution deferral projects in requesting Commission approval of selected deferral projects?

2.4.4. DPAG Timelines

As visualized in Figure 1, the DPAG would convene following the IOUs' submission of the GNA, which would be due by a to-be-determined date in April or May each year. Staff proposes two months for the DPAG to complete its review of the GNA and develop the portfolio of distribution deferral projects to go out for solicitation.

For the IDER Incentives Pilot, D.16-12-036 allotted two months for the IOUs to submit the Tier 3 advice letter following completion of the DPAG process, followed by four months for Commission review and disposition of the IOUs' request to launch an RFO. Such timelines reflect the need for additional review of the IOUs' deferral project selection for purposes of the pilot, but are likely too lengthy for the recurring annual Deferral Framework. Here we propose the IOUs' Tier 3 advice letter and IPE's DPAG report be filed one month following completion of the DPAG process, followed by two months for Commission review and disposition.

Once the Commission issues a final disposition on the DPAG Recommended Projects, the IOUs will update the LNBA Public Tool and Heat Map to inform the DER marketplace of the locations and estimated value of approved distribution deferral projects in advance of a solicitation.

Ultimately, DPAG timelines and deliverables will need to be coordinated with parallel DRP Track 3 procedural activities regarding the GNA, Grid Modernization Framework, and the new DRP process generally.

Stakeholder questions:

19. Referencing Figure 1, do you agree with Staff's proposed timelines for annual DPAG review, submission of DPAG Recommended Projects and DPAG Report, and Commission disposition? How can these timelines be modified or improved?

3. Solicitation Process, Other DER Sourcing Mechanisms, and Subsequent Deferral Framework Updates

The portfolio of Commission-approved distribution deferral projects will be procured via the IDER Competitive Solicitation Framework (CSF). Details of the CSF were finalized in the *Competitive Solicitation Framework Working Group Final Report*, filed August 1, 2016 and adopted in D.16-12-036.

For the IDER Incentives Pilot, D.16-12-036 allocated four months for the RFO portion of the CSF process following Commission approval of pilot deferral projects. Contracts that result from the CSF would be subsequently submitted for Commission approval via a Tier 2 advice letter.

For the ongoing Deferral Framework, we propose that the CSF RFO launches no later than two months following Commission disposition of the DPAG's deferral project request. While elements and timelines specific to the CSF RFO remain in scope in the IDER proceeding, future IDER deliberations on a permanent CSF must consider the need to expedite the solicitation and approval processes that occur on an ongoing basis. Staff stresses the need to gain efficiencies wherever possible in the ongoing DRP process, such that the time between the annual IEPR update and launching a DER solicitation is minimized.

Along these lines, and as detailed in Section 1.2, a major limitation of the CSF as a sourcing mechanism is that it is not able to procure DERs to meet grid needs with relatively short (i.e., less than three-year) lead-times, due to the time required to solicit, contract, construct, and interconnect a DER project. In the IDER Incentives Pilot, this rendered virtually all voltage projects out of consideration, as those types of mitigations are typically needed within zero-to-two years.

We highlight the need for the IDER proceeding to develop streamlined non-RFO DER sourcing mechanisms that allow for short lead-time grid needs to be met with DER non-wires alternatives. This could include establishing a pool of pre-approved vendors that could, for example, replace solar customers' legacy inverters with smart inverters to provide voltage support services, or deploy turnkey DER solutions that provide back-tie services. The Commission could grant streamlined approval to certain projects that come in under a given cost threshold or meet a number of pre-established conditions. In addition, learnings from the IDER Incentives Pilot may result in determinations by the Commission on matters such as the piloted 4% shareholder incentive.

Regardless of how future DER sourcing mechanisms and incentives take shape, the nascence of regulatory constructs around procuring DER grid services necessitates that the Deferral Framework is able to flexibly evolve in response to new sourcing mechanisms developed in the IDER proceeding. Modifications to such elements as initial deferral screening criteria, prioritization metrics, and DPAG timelines likely do not merit re-evaluation in a Commission rulemaking. We thus propose the establishment of a Tier 2 advice letter process for the IOUs to propose minor changes to various aspects of the Deferral Framework. The need for such changes could be identified in the IDER proceeding, in the ongoing DPAG, or on Staff's own motion, and would likely entail a Commission workshop to build further consensus around the proposed changes. In any case, such a process would ensure that the goals of P.U. Code §769 are continually met by enabling the Deferral Framework to provide the oversight and advisory functions required by the latest developments in DER sourcing.

Stakeholder questions:

20. Is Staff's proposal to launch the CSF RFO two months after Commission disposition of DPAG Recommended Projects adequate?
21. Referencing Figure 1, where can efficiencies be gained in the overall DRP process specific to the Deferral Framework to shorten the time between IEPR update and launching the DER solicitation?
22. Do you agree with Staff's proposed Tier 2 advice letter process for minor changes to elements of the ongoing Deferral Framework? How could this proposal be modified or clarified?

4. Cost Recovery

DER projects that are procured through the CSF or future sourcing mechanism shall be pre-approved for cost recovery over the length of the contract, similar to cost recovery for Renewable Portfolio Standard projects. DER payments will be tracked in the existing IDER Incentives Pilot balancing accounts, which can be repurposed for DER payments and IOU incentives for distribution deferral projects on an ongoing basis. Costs for DER payments will be recovered through the applicable accounting mechanism that balances collection of the distribution revenue requirement.

The actual value of deferred investments should be recorded and tracked over time as distribution deferral projects are authorized and as DER projects come online to provide contracted grid services.

Stakeholder questions:

23. What is the best method for tracking the value of deferred investments over time? Should they be presented in an attachment to the Grid Needs Assessment, show up as a credit to otherwise-requested budgets in the GRC, or other method?
24. Given the existing flexibility to repurpose approved GRC budgets for emergent priorities or changed forecasts, how can the Commission guarantee that distribution investments that are deferred or avoided by DER alternatives actually result in net ratepayer benefits?

Appendix A: Technical Glossary

- **Capacitor banks** – A grouping of several capacitors which are used to control reactive power and voltage.
- **Conservation Voltage Reduction (CVR)** – A technique for improving the efficiency of the electrical grid by optimizing voltage on feeder lines, achieved by installing equipment that keeps voltage towards the bottom end of the acceptable range. This reduces energy consumption and helps avoid high voltage spikes that damage equipment, thus avoiding adverse effects on consumer's appliances.
- **Line conductors** – A wire that allows the flow of an electrical current.
- **Line voltage regulators** – A device that automatically maintains a constant voltage level along a line conductor.
- **Load tap changers** – A mechanism that regulates the output voltage of a transformer.
- **Substation Transformers** – Transformers located at substations that change voltage levels between high transmission voltages and lower distribution voltages.
- **Thermal capacity upgrade projects** – Any distribution infrastructure project aimed at increasing the thermal capacity (i.e., the electric power output for which system components are rated) of the distribution system in response to changing conditions. Such projects typically entail upgrades to line conductors or transformers.
- **Voltage/var Optimization (VVO)** – The process of optimally managing voltage levels and reactive power to achieve more efficient grid operations by reducing system losses, peak demand, energy consumption, or a combination of the three. CVR is a subset of VVO.

(END OF ATTACHMENT A)