PUBLIC UTILITIES COMMISSION
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December 10, 2019

Advice Letter 5688-E

Erik Jacobson
Director, Regulatory Relations
c/o Megan Lawson
Pacific Gas and Electric Company
77 Beale Street, Mail Code B13U
P.O. Box 770000
San Francisco, CA 94177

Subject: Approval of Pacific Gas and Electric Company's (PG&E) Request for Approval to Issue Competitive Solicitations for Distributed Energy Resource (DER) Procurement for Electric Distribution Deferral Opportunities

Dear Mr. Jacobson,

Advice Letter (AL) 5688-E (filed November 15, 2019) was not protested and is approved effective December 16, 2019. Hence, this letter approves PG&E's request to launch a competitive solicitation of the following four candidate DER distribution deferral projects in compliance with Decision D.18-02-004 and subsequent rulings in Proceeding R.14-08-013:

1. Alpaugh New Feeder
2. Calflax Bank 2
3. Santa Nella Bank and New Feeder
4. FMC 1102

In AL 5688-E, PG&E did not include a request to solicit a DER deferral project for the $18.5 million Estrella Substation planned investment. The Independent Professional Engineer (IPE) report attached to AL 5688-E states, "We recommend that the consideration of the Estrella distribution project within the DIDF [Distribution Investment Deferral Framework] be continued and that to support that objective the consideration be put on a different timeline than the PG&E recommended Tier 1 projects" (AL 5688-E, Attachment E, page 24). Among the IPE's questions are, "What steps could be taken to address capacity needs that are predicted to occur prior to the in-service date of 2024?"

We agree with the IPE that the Estrella Substation deferral opportunity deserves further review, and Energy Division will continue to assess this planned investment either prior to or during the 2020-21 Distribution Resources Planning cycle in an appropriate procedural forum. We also note that PG&E's Estrella Substation planned investment is the subject of an open proceeding A.17-01-023. Energy Division staff are preparing a Draft Environmental Impact Report pursuant to the California Environmental Quality Act that will consider DER-based alternatives to the distribution components of the proposed substation. The proposed Estrella Substation would have a 230/70-kV transmission yard that would be owned by Horizon West Transmission and a separate 70/21-kV distribution yard that would be owned by PG&E. For further details, see: https://www.cpuc.ca.gov/environment/info/horizonh2o/estrella/index.html

Advice Letter 5688-E is approved.

Sincerely,

FOR

Edward Randolph
Deputy Executive Director for Energy and Climate Policy/
Director, Energy Division

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Service lists copied for:
R.14-08-013, R.14-10-003, and A.17-01-023

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November 15, 2019

Advice 5688-E
(Pacific Gas and Electric Company ID U 39 E)

Public Utilities Commission of the State of California

Subject: **Request for Approval to Issue Competitive Solicitations for Distributed Energy Resource (DER) Procurement for Electric Distribution Deferral Opportunities**

Purpose

Pursuant to Ordering Paragraphs (OP) 2.w and 2.x of Decision (D.) 18-02-004 and the May 7, 2019, Administrative Law Judge (ALJ) Ruling modifying the Distribution Investment Deferral Framework, Pacific Gas and Electric Company (PG&E) submits this Tier 2 advice letter requesting the California Public Utilities Commission's (Commission's or CPUC's) approval to issue competitive solicitations to procure distributed energy resources (DER) solutions for identified electric distribution deferral opportunities as described below.

1. Background

On August 14, 2014, the Commission instituted Rulemaking (R.) 14-08-013 to establish policies, procedures, and rules to guide the California investor-owned utilities (IOUs) in developing their Distribution Resources Plan proposals. This rulemaking also established new polices to evaluate the IOUs' existing and future electric distribution infrastructure and planning procedures with respect to incorporating DERs into the planning and operations of their electric distribution systems.

In July 2015, California IOUs each submitted their respective Distribution Resources Plan (DRP) proposals to the Commission. The Commission organized the review of the DRP filing content into three tracks: Track 1 – Tools and Methodologies, Track 2 – Field Demonstration Projects, and Track 3 – Policy Issues. Various DRP working group meetings and workshops were held to inform the Commission and stakeholders, which ultimately led to several decisions in R.14-08-013.

In February 2018 the Commission issued D.18-02-004 on Track 3 Policy Issues, sub-track 1 (Growth Scenarios) and sub-track 3 (Distribution Investment and Deferral

Process). This decision directed the IOUs to file a Grid Needs Assessment (GNA) by June 1 of each year, and a Distribution Deferral Opportunity Report (DDOR) by September 1 of each year. Subsequently, on July 7, 2019, assigned Administrative Law Judge Mason issued a Ruling modifying the Distribution Investment Deferral Framework.

PG&E jointly filed its second GNA and DDOR on August 15, 2019 and provided it to its Distribution Planning Advisory Group (DPAG). Also, as required by D.18-02-004, PG&E initiated DPAG meetings by September 20, 2019 to receive advisory input on candidate distribution deferral opportunities that should be issued for competitive solicitation and retained an Independent Professional Engineer (IPE) to attend the meetings and prepare a DPAG Report.

This advice letter is submitted in compliance with D.18-02-004, the November 19, 2018, and July 7, 2019, ALJ Ruling regarding the application of the competitive solicitation framework (CSF) for distribution investment deferrals in the distribution resource planning (DRP) proceeding.

2. Overview of the Distribution Investment Deferral Framework Process

Pursuant to the DIDF as specified in D.18-02-004 and the May 7, 2019, ALJ Ruling, PG&E:

- Submitted PG&E's 2019 Grid Needs Assessment (GNA) Report: August 15, 2019
- Submitted PG&E's 2019 Distribution Deferral Opportunity Report (DDOR): August 15, 2019
- Hosted PG&E's DPAG Meeting #1: September 19, 2019
- Hosted PG&E's DPAG Meeting #2 via Webinar: October 7, 2019
- Republished PG&E's 2019 Grid Needs Assessment (GNA) Report: November 15, 2019
- Republished PG&E's 2019 Distribution Deferral Opportunity Report (DDOR): November 15, 2019

This advice letter requests approval of the distribution deferral opportunities that were a result of the DPAG's advisory input on the DDOR.

3. Lessons Learned from Prior DER Solicitations for Distribution Deferral

PG&E has gathered valuable learnings from both its DRP Demonstrations and its Integrated Distributed Energy Resources (IDER) Incentive Pilot. General learnings and insights gathered from progress to-date on IDER Incentive Pilots across all California IOUs are included in the *Energy Division Staff Proposal on a Distribution Investment Deferral Framework (Staff Proposal)*, issued on June 30, 2017 and referenced in the *Decision on Track 3 Issues: DER Growth Scenarios and the Distribution Investment Deferral Framework (DIDF)* (D.18-02-004) issued on February 15, 2018. As described in these filings, the adoption of a CSF and establishment of an interim DPAG has provided the IOUs, including PG&E, tangible learnings on the deferral screening criteria and prioritization metrics, which have been incorporated into the DIDF process. PG&E discussed solicitation streamlining suggestions in recently filed comments on the *Amended Scoping Memo of Assigned Commissioner and Joint Ruling with Administrative Law Judge* dated February 12, 2018.[1]

3.1. Lessons Learned from IDER Incentive Pilot

PG&E's development of the Gonzales Substation distribution deferral opportunity as part of the IDER Incentive Pilot reinforce these general learnings.

On June 16, 2017, PG&E submitted Advice Letter (AL) 5096-E in compliance with Step-Three of D.16-12-036, for the selected deferral candidate project, the Rincon Substation in Sant Rosa. However, due to the Santa Rosa fire in the North Bay, the Rincon project was no longer viable, and PG&E notified the Commission via comments on Res. E-4889.

Pursuant to Res. E-4889 issued on December 19, 2017, PG&E submitted supplemental AL 5096-E-A on May 1, 2018, explaining the circumstances surrounding the cancellation of the Rincon project, detailing lessons learned and insights as well as a proposal for selection of a new candidate project, the Gonzales Substation in Monterey County. On April 25, 2019, PG&E submitted AL 5531-E, requesting approval of contracts with front of the meter storage provider GCL, to defer the substation upgrade at that location.

The Gonzales area need was for short-duration (4 hour) need, that required dispatch no more than 15 days per year. The ability to successfully execute a transaction at this location validates PG&E's prioritization metric for short duration.

During the solicitation process, the identified need at Gonzales increased from 2 MW to 2.75 MW. PG&E negotiated with the counterparty to provide additional MW beyond what had originally bid to meet the increased need, plus a small buffer. This experience highlights the uncertainty in load forecasting, the flexibility that distribution planners need to have in addressing changing needs on the distribution system, and the challenges that these two factors pose for identifying projects and conducting a solicitation of DERs for distribution deferral.

3.2. Lessons Learned from 2019 DIDF RFO

The 2019 DIDF RFO is currently underway, and thus the results of the RFO are still confidential. One lesson learned from the ongoing RFO is the need to consider the ability of energy storage to charge from the need locations identified. This lesson learned was applied below to the Calfax Bank 2 candidate deferral opportunity (Section 4.2.1).

[1] See *Joint Comments of Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company on Amended Scoping Memo of Assigned Commissioner and Joint Ruling with Administrative Law Judge* filed in R.14-10-003 (March 29, 2018).

3.3. Application of Lessons Learned

PG&E has incorporated, to the extent possible, the lessons learned from prior solicitations to the 2019-20 DIDF cycle. For example, PG&E prioritization metrics are designed to prioritize candidate deferral opportunities with short duration needs. PG&E also considered the ability of energy storage to charge from the locations identified for each candidate deferral opportunity. PG&E has also carefully reviewed Supervisory Control and Data Acquisition (SCADA) and Advanced Meter Infrastructure (AMI) data to identify opportunities to limit the duration of the needs required. PG&E may also consider procurement above the minimum performance and operational requirements if it is cost-effective to address forecast uncertainty.

4. Proposal to Solicit Candidate DER Distribution Deferral Projects

PG&E is requesting approval to solicit candidate DER distribution deferral projects via the CSF RFO for the following candidate distribution deferral opportunities:

- Alpaugh New Feeder (4.4 MW)
- Calflax Bank 2 ([redacted] MW)
- Santa Nella Bank and New Feeder (9.3 MW)
- FMC 1102 (0.8 MW)

The following information is provided on the candidate distribution deferral opportunities:

- Location of Needs (map and description of locations on circuit) – Attachment C
- Metrics to Define Need (Expected Performance and Operational Requirements) – see Section 4.3.1
- Unit Cost of Traditional Mitigation – Attachment D
- Prioritization Metrics (cost-effectiveness, market assessment, and forecast certainty) – see Section 4.1
- Services Required – All three candidate deferral opportunities are thermal capacity requirements.

4.1. Prioritization Metrics

In D.18-02-004, three metrics were adopted to characterize and help prioritize projects on the candidate deferral shortlist. These metrics are: a) Cost-Effectiveness, b) Forecast Certainty, and c) Market Assessment.

PG&E has evaluated each of these metrics qualitatively, grouping the candidate deferral opportunities into tiers based on their relative rankings. The prioritization metrics incorporate lessons learned from prior solicitations as described in Section 3. For example, candidate deferral opportunities that have baseload (24/7) operational requirements were given a relatively low ranking.

For ease of summarizing prioritization metric results, PG&E has developed a 4-tier system, where each tier represents PG&E's proposed priority ranking of those candidate deferral projects likelihood of success for DER sourcing. The following table (Table 1) summarizes PG&E's proposed 4-tier system.

Table 1: PG&E's 4-Tier Prioritization System

Tier	Color Designation	Definition
1		Relatively High Ranking
2		Relatively Moderate Ranking
3		Relatively Low Ranking
4		Already Sourced Elsewhere

All ranking of projects is relative. For example, a higher tiered project does not indicate that the project will be cost-effective, have a certain forecast, or have a robust market.[2] It only indicates the ranking of the candidate deferral opportunity relative to other candidate deferral opportunities.

PG&E's preliminary prioritization and ranking of candidate deferral opportunities were published in PG&E's 2019 DDOR. The prioritization metrics and tiering were then thoroughly discussed and updated throughout the DPAG process. The prioritization metrics for each candidate deferral opportunity are included in Attachment A.

4.2. Candidate Deferral Opportunities

The following table (Table 2) summarizes the tiering of PG&E's 2019 final candidate deferrals, including the targeted in-service need date and minimum grid capacity needed (i.e., deficiency).

Table 2: PG&E's 2019 DDOR Candidate Deferral Location Summary

Tier	Candidate Deferral	In-Service Date	Deficiency (MW)
1	Alpaugh New Feeder	2022	4.4
	Calflax Bank 2	2023	[redacted]
	Santa Nella New Bank & Feeder	2022	9.3
	FMC 1102	2023	0.8
2	Camp Evers 2107	2022	0.9

[2] For example, blue candidate deferral opportunities are expected to be more cost-effective than red candidate deferral opportunities, but it does not indicate the candidate deferral opportunity will receive conforming and cost-effective bids. Similarly, all the opportunities have some degree of forecast uncertainty.

Tier	Candidate Deferral	In-Service Date	Deficiency (MW)
	Brentwood 2105	2022	1.2
3	Estrella Substation	2024	19.4
	Pueblo Bank 3	2022	23.2
	Oceano 1106	2022	1.2
	Rosedale 2102	2022	1.8
	Rob Roy 2105	2022	3.0
	Peabody 2106	2022	[redacted]
	Madison 2101	2022	
	Martin SF H 1108	2022	1.0
	Martin SF H 1107	2022	1.8
	Avenal 2101	2022	[redacted]
	Edenvale 2108	2022	1.5
	Dairyland 1110 New Feeder	2022	4.5

PG&E has identified 18 Candidate Deferral Opportunities totaling approximately 83 megawatts (MW), which are further categorized and prioritized into the following three tiers:

- *Tier 1*: Identified four Candidate Deferral Opportunities totaling approximately 19.3 MW. Tier 1 Candidate Deferral Opportunities are relatively more likely to be deferrable.
- *Tier 2*: Identified two Candidate Deferral Opportunities totaling approximately 2.1 MW. Tier 2 Candidate Deferral Opportunities have identified some red flags that indicate they are unlikely to be successfully deferred now. PG&E recommends not pursuing these Candidate Deferral Opportunities, but to closely monitor status and project conditions and re-evaluate for a future date.
- *Tier 3*: Identified twelve Candidate Deferral Opportunities totaling approximately 62 MW. Tier 3 Candidate Deferral Opportunities have multiple major red flags that have been identified and indicate it is not likely a DER deferral solution can successfully be sourced.

4.2.1. Tier 1 Candidate Deferral Opportunities

PG&E's recommendation is to pursue competitive solicitations for the Tier 1 Candidate Deferral Opportunities (four projects totaling 19.3 MW). The operational and service requirements are specified in Section 4.3.1 (Expected Performance and Operational Requirements). The Tier 1 candidate deferral opportunities were selected based on their relative ranking using the prioritization metrics (Attachment A). The Tier 1 candidate deferral opportunities had shorter duration needs, less frequent calls per year, and are more likely to be cost-effective.

The Tier 1 candidate deferral opportunities are:

- *Alpaugh New Feeder* – The planned investment consists of installing a new breaker, 2 miles of double circuit, 3 miles of reconductoring, 1 regulator, and 4 switches, with an expected in-service date of April 1, 2022. In comparison with the other candidate deferral opportunities, Alpaugh scores relatively high on forecast certainty and does not have any red flags.

- *Calflax Bank 2* – The planned investment consists of installing a new substation bank (i.e. Bank 2) at Calflax Substation and installing a new breaker with an expected in-service date of April 1, 2023. The expected performance and operational requirements include long duration requirements but at only one location. Due to charging constraints at this location, energy storage bids that solely rely on charging from the grid at the location of need will not be considered viable. In comparison with the other candidate deferral opportunities, Calflax does not have any red flags.

- *Santa Nella Bank 1 and New Feeder* – The planned investment consists of replacing the existing Santa Nella Bank 1 with a 30 MVA bank and installing a new 12 kV feeder, with an expected in-service date of April 1, 2022. In comparison with the other candidate deferral opportunities, Santa Nella does not have any red flags.

  The Santa Nella Candidate Deferral Opportunity was included in PG&E's November 2018 Advice Letter[3] and was approved for solicitation. Negotiations for the Santa Nella Candidate Deferral Opportunity are currently underway, and PG&E has until December 2, 2019 to submit an Advice Letter requesting approval of a contract, if executed. PG&E is requesting for approval to re-solicit the Santa Nella Candidate Deferral Opportunity as part of the approved contingency plan for Santa Nella in this advice letter. PG&E would only resolicit for Santa Nella if there was not a viable DER alternative from the 2018-19 DIDF cycle RFO.

- *FMC 1102* – This planned investment consists of installing a breaker and extending 250 feet of underground circuit, with an expected in-service date of April

[3] PG&E Advice Letter 5435-E

1, 2023. Although preliminarily ranked as a Tier 2 candidate deferral opportunity because FMC has red flags under the market assessment prioritization metric, PG&E has moved FMC 1102 into Tier 1 and is requesting to solicit the FMC 1102 candidate deferral opportunity based on feedback at the DPAG meetings and from the IPE. FMC 1102 is meeting a reliability need, and the performance and operational requirements include real-time dispatch and provide a learning opportunity for market participants and stakeholders. As described in Section 5.1, PG&E would solicit for the FMC 1102 candidate deferral on a different schedule than the other Tier 1 opportunities.

4.2.2. Tier 2 Candidate Deferral Opportunities

PG&E does not recommend pursuing competitive solicitations for Tier 2 candidate deferral opportunities at this time, for the following reasons:

- *Camp Evers 2107* – has red flags under the market assessment prioritization metric and thus is not recommended for solicitation at this time. Camp Evers does not have sufficient back-ties to keep customers energized in the event of an outage. Hence, real time and islanding capabilities are required. Based on the lessons learned the opportunity is unlikely to be successfully sourced.

- *Brentwood 2105* – has red flags under the market assessment prioritization metric and thus is not recommended for solicitation at this time. Brentwood does not have sufficient back-ties to keep customers energized in the event of an outage. Hence, real time and islanding capabilities are required. Based on the lessons learned the opportunity is unlikely to be successfully sourced.

4.2.3. Tier 3 Candidate Deferral Opportunities

PG&E does not recommend pursuing competitive solicitations for Tier 3 candidate deferral opportunities. The Tier 3 projects have multiple major red flags that have been identified and indicate that it is unlikely a DER deferral solution can successfully be sourced. Most of the Tier 3 projects have real-time and islanding requirements which are unlikely to be successfully sourced. Per the feedback from DPAG members and the IPE, PG&E has examined the Estrella Substation candidate deferral opportunity to determine if the reliability requirements could be separated and removed from the Expected Performance and Operational Requirements. PG&E has determined that the reliability requirements cannot be removed from the Expected Performance and Operational Requirements and Estrella Substation remains a Tier 3 candidate deferral opportunity.

4.3. Technical and Operating Requirements

Since the filing of the DDOR and based on feedback from the DPAG, PG&E has continued to perform detailed engineering analysis to refine the expected performance and operational requirements for the candidate deferral opportunities, including:

- Updated load forecast to reflect any significant changes (e.g., new customer requests)
- Examination of historical SCADA data and AMI data
- Examination of grid topology and the interdependencies of grid needs
- Examination of temperature data to examine how often overload is expected to occur

4.3.1. Expected Performance and Operational Requirements

The expected performance and operational requirements are listed below in Table 3 for the Tier 1 candidate deferral opportunities. For each of the candidate deferral opportunities listed, all of the expected performance and operational requirements need to be met in order to defer the planned investment. Based on DPAG feedback, requirements may be grouped into smaller blocks. Further details on these requirements will be provided during the 2020 DIDF RFO Participants Webinar.

Table 3: Expected Performance and Operational Requirements

Candidate Deferral	Grid Need Location	Real Time (RT) or Day Ahead (DA)	Offer Size (MW)	Delivery Months	Calls/Year	Delivery Hours	Hours Duration
Alpaugh New Feeder	Corcoran 1112	DA	4.4	Jun-Sep	113	3:00PM-10:00PM	7
Calflax Bank 2	Calflax Bank 1	DA	[redacted]				
	Canal Bank 1	DA	1.2	Jun-Aug	75	5:00PM-8:00PM	3
Santa Nella	Canal 1103	DA	4	Jun-Sep	122	3:00PM-10:00PM	7
	Ortiga 1106	DA	3.8	Jun-Sep	122	4:00PM-10:00PM	6
FMC 1102	FMC 1101	RT	0.8	Jun-Sep	4	12:00AM-12:00AM	12

The expected performance and operational requirements for the Tier 1 candidate are described further below:

- *Alpaugh New Feeder* – One grid need, located on the Corcoran 1112 feeder.

- *Calfax Bank 2* – One grid need, located on the Calflax Bank 1.

- *Santa Nella Bank and New Feeder* – Three grid needs, located on the Canal Bank 1, Canal 1103 feeder, and Ortiga 1106 feeder. For the solicitation, PG&E has specified performance and operational requirements for each of the independent grid needs. PG&E encourages, but not does not require, that Participants submit an offer for all three of the grid needs.

- *FMC 1102* – One grid need, located on FMC 1101. There is a Real Time requirement on this circuit, so the DER is expected to provide services within a 5-minute dispatch window.

4.3.2. Deferral Term

PG&E determines the term of the deferral to the end of the forecasting period (2029). The terms for the candidate deferral opportunities is based on the expected in-service date as follows:

- *Alpaugh New Feeder* – 7-year term
- *Calfax Bank 2* – 6-year term
- *Santa Nella Bank and New Feeder* – 7-year term
- *FMC 1102* – 6-year term

5. Competitive Solicitation Framework

5.1. RFO Schedule

PG&E's RFO schedule is linked to final approval of the Solicitation Process. PG&E plans to conduct the RFO pursuant to the schedule in the RFO Protocol, assuming CPUC approval has been received. To the extent necessary to ensure a successful RFO and/or successful negotiation and execution of a contract with a DER supplier or suppliers to meet the deferral needs, PG&E reserves the right to request an adjustment to the schedule. PG&E's anticipated RFO schedule is shown in Table 5 below.

Table 5A: PG&E's Anticipated RFO (Alpaugh, Calflax, Santa Nella[4]) Schedule

Date	Activity
Day 0	CPUC Approval of RFO
Day 30	Issue RFO
Day 37	Bidder’s Webinar
Day 90	Offers Due
Day 135	Shortlist
Day 140	Sellers accept shortlist position
Day 230	Complete negotiations and execute transaction
Day 260	File transactions for CPUC approval

Table 5B: PG&E's Anticipated RFO (FMC 1102) Schedule

Date	Activity
Day 0	CPUC Approval of RFO
Day 128	Issue RFO
Day 135	Bidder’s Webinar
Day 195	Offers Due
Day 240	Shortlist
Day 245	Sellers accept shortlist position
Day 335	Complete negotiations and execute transaction
Day 365	File transactions for CPUC approval

5.2. Market Outreach

PG&E will conduct market outreach in a similar manner to other recent distribution deferral solicitations (e.g., 2018-19 cycle DIDF RFO). Specifically, PG&E will dedicate a section of its company website to the solicitation, providing a means for interested parties to download the RFO Protocol/Instructions and related materials. PG&E will notify its RFO distribution list, which includes over 2,700 market participants, and will notify the over 240 individuals from the DPAG and CPUC DRP and IDER proceeding service lists that the RFO will be released and invite them to participate.

In addition, PG&E will hold Participants’ webinar to provide an overview of the DIDF solicitations. The webinar will provide potential counterparties an opportunity to learn more about the solicitation, hear presentations, and ask questions. There will be additional opportunities to ask questions via email following the webinar. The Independent Evaluator (IE) will monitor PG&E’s outreach and report on the adequacy of its outreach efforts when the solicitation has been completed.

5.3. Project Evaluation Metrics to Select a Bid

[4] Santa Nella will be solicited as part of the contingency plan only if current negotiations do not result in a viable DER alternative from the 2019 DIDF RFO, as described in Section 4.2.1.

PG&E will evaluate individual Offers and/or construct different portfolios of Offers that meet the area need. PG&E's evaluation will apply "least-cost, best-fit" principles, using quantitative and qualitative criteria to evaluate the submitted Offers, which may include, but are not limited to:

Quantitative Attributes:

a) Benefits (Distribution Deferral Value)
b) Fixed and Variable Costs, including Customer Engagement Support costs

Qualitative Attributes:

a) Project Viability (experience, technology viability, interconnection, site control)
b) Supply Chain Responsibility
c) Technology, Counterparty Concentration
d) Safety
e) Ability to meet entire need

6. Contingency Plan

PG&E has contingency plans for each of the candidate deferral opportunities recommended for solicitation, based on three different stages of the potential DER deferral:

- *DER Solicitation or Contract Negotiation Stage:* If a contingency such as no cost-effective or combination of cost-effective bids meet the grid need or a change to the forecasted grid need should arise during the solicitation or contract negotiation stage, PG&E will perform a root cause analysis to determine the cause of the failure and the best corrective action. If time and regulatory processes allow, PG&E will consider contracting with alternative bids or administering a revised solicitation. Otherwise, PG&E will move forward with the best alternative wires solution to ensure the safe and reliable provision of distribution services to customers.

- *DER Implementation Stage*: If a contingency such as a failure to meet implementation milestones or achieve operations by the identified grid need date, or a change in the forecasted grid need should arise during the DER implementation stage, PG&E will perform a root cause analysis to determine the cause of the failure and the best corrective action. If time and regulatory processes allow, PG&E will consider administering a revised DER solicitation. Otherwise, PG&E will move forward with the best alternative wires solution to ensure the safe and reliable provision of distribution services to customers.

- *Commercial Operation Stage:* If a contingency such as a failure of a contracted DER resource to meet the expected performance and operational requirements during the commercial operation stage, PG&E will handle the contingency in the same manner as any other failed equipment. The immediate emergency response may include distribution operations personnel implementing load transfers based on current loading profiles, installation of mobile generation, and/or a plan to interrupt power for local customers as a last resort. The contingency plan beyond the initial 24 hours would consider the area loading, the expected duration of the DER resource failure, any potential transfers that may be available because of recent distribution infrastructure additions or improvements, the installation of temporary facilities such as a mobile transformer bank, and the re-rating of distribution facilities. If a longer-term mitigation is needed, PG&E may move forward with the best alternative wires solution in order to ensure the safe and reliable provision of distribution services to customers.

In order to ensure the safe and reliable provision of distribution services should a contingency arise, the engineering, design and major equipment procurement for the planned investment will continue until contract approval by the Commission of any DER deferral solution. Table 6 below identifies when these activities are expected to start for the planned investments. PG&E will base the contract performance requirements and off ramps on the expected milestones listed below.

Table 6: Expected milestones for planned actives for Planned Investments

Project Name	Project Initiation	Engineering/Design Start Date	Major Equipment Procurement	Construction Start Date	Forecasted In-Service Date
Alpaugh New Feeder	2/1/2020	4/1/2020	10/1/2020	10/1/2021	4/1/2022
Calflax Bank 2	2/1/2021	4/1/2021	10/1/2021	10/1/2022	4/1/2023
Santa Nella Bank and New Feeder	2/1/2020	4/1/2020	10/1/2020	10/1/2021	4/1/2022
FMC 1102	2/1/2021	4/1/2021	10/1/2021	10/1/2022	4/1/2023

While the DER service requirement would potentially defer the planned investment, it does not provide any margin for load forecast uncertainty. Any increase in the load forecast (e.g., due to new load requests) may result in the solicited DER solution no longer deferring the planned investment. If the grid needs were to increase, the DER service requirement would no longer be sufficient, and the planned investment may no longer be deferred. Additionally, DER resources are procured to meet specific hours and days, and the planned investment may still be required if the timing of the load forecast changes and the grid need is no longer met by the procured resources. Therefore, even if DER resources are procured to meet the specified grid need, the planned “wires” investment may still be required if the load forecast changes and the grid need is no longer met by the procured resources.

PG&E will consider procuring additional DERs if the system need increases, and if the additional DERs can be procured cost-effectively and still meet the required in-service date. PG&E does not plan to change terms of the contract once the contract is executed and approved. PG&E does not plan on cancelling any contracts once the contract is executed and approved by the Commission, even if there is a change in the load forecast and the planned investment is no longer deferred.

7. Recording and Recovery of Procurement Costs

PG&E's preliminary estimate of the cost-effectiveness cap for the Tier 1 candidate deferral opportunities, including the Unit Cost of the Traditional Mitigation, are included in Attachment D. PG&E may revise the initial cost-effectiveness cap shown in the attachment based on additional information, including regarding incremental direct and indirect costs, that becomes available between now and contract execution. Any revisions to the preliminary cost-effectiveness cap calculation shown in the attachment will be included in the Tier 2 advice letter requesting Commission approval of executed contracts for the DIDF.

PG&E requests approval of its incremental administrative costs for its DIDF solicitation, including for the solicitation process and other non-procurement costs. The incremental administrative costs approved in this advice letter are considered pre-approved for recording and recovery and will be reviewed by the Commission in PG&E's General Rate Case.[5] Any administrative costs exceeding the forecast approved in this advice letter are subject to a reasonableness review. The annual distributed energy resources contract costs, having been pre-approved, will be recovered over the life of the contract. For the reasons stated in its comments on the utility regulatory incentive pilot in R.14-10-003 and on D.16-12-036, PG&E is not requesting to apply a four percent (4%) pre-tax incentive to the annual payment for the distributed energy resource.

PG&E will track all incremental administrative costs of the solicitation, including unavoidable expenditures for commissioning and ongoing testing and verification of the Contract and Contract administrative costs in PG&E's DER Distribution Deferral Account (Electric Preliminary Statement Part GZ). Pursuant to PG&E's contingency plan as specified in Section 6 above and the May 7, 2019, Administrative Law Judge (ALJ) Ruling modifying the Distribution Investment Deferral Framework, contingency costs, including unavoidable expenditures (e.g., design and engineering) on any planned wires-related investments, also will be tracked and recorded in the DER Distribution Deferral Account.

8. Commission Action Requested

Pursuant to D.18-02-004, PG&E requests that the Commission approve issuance of a CSF RFO to procure DERs for the four Tier 1 candidate distribution deferral sites.

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[5] The proposed ratemaking treatment for incremental administrative costs associated with PG&E's DIDF Solicitation is consistent with D.16-12-036 and OP 2.aa of D.18-02-004.

Tariff Revisions

The submittal would not increase any current rate or charge, cause the withdrawal of service, or conflict with any rate schedule or rule.

Protests

Anyone wishing to protest this submittal may do so by letter sent via U.S. mail, facsimile or E-mail, no later than December 5, 2019. Protests must be submitted to:

CPUC Energy Division
ED Tariff Unit
505 Van Ness Avenue, 4th Floor
San Francisco, California 94102

Facsimile: (415) 703-2200
E-mail: EDTariffUnit@cpuc.ca.gov

Copies of protests also should be mailed to the attention of the Director, Energy Division, Room 4004, at the address shown above.

The protest shall also be sent to PG&E either via E-mail or U.S. mail (and by facsimile, if possible) at the address shown below on the same date it is mailed or delivered to the Commission:

Erik Jacobson
Director, Regulatory Relations
c/o Megan Lawson
Pacific Gas and Electric Company
77 Beale Street, Mail Code B13U
P.O. Box 770000
San Francisco, California 94177

Facsimile: (415) 973-3582
E-mail: PGETariffs@pge.com

Any person (including individuals, groups, or organizations) may protest or respond to an advice letter (General Order 96-B, Section 7.4). The protest shall contain the following information: specification of the advice letter protested; grounds for the protest; supporting factual information or legal argument; name, telephone number, postal address, and (where appropriate) e-mail address of the protestant; and statement that the protest was sent to the utility no later than the day on which the protest was submitted to the reviewing Industry Division (General Order 96-B, Section 3.11).

Effective Date

PG&E requests that this Tier 2 compliance advice submittal become effective on either the date of Energy Division disposition approving the advice letter or, if necessary, the date of the Commission Resolution approving the advice letter.

The version of this advice letter posted at www.pge.com is redacted.

Notice

In accordance with General Order 96-B, Section IV, a copy of this advice letter is being sent electronically and via U.S. mail to parties shown on the attached list and the parties on the service lists for R.14-08-013 and R.14-10-003. Address changes to the General Order 96-B service list should be directed to PG&E at email address PGETariffs@pge.com. For changes to any other service list, please contact the Commission's Process Office at (415) 703-2021 or at Process_Office@cpuc.ca.gov. Send all electronic approvals to PGETariffs@pge.com. Advice letter submittals can also be accessed electronically at: http://www.pge.com/tariffs/.

/S/
Erik Jacobson
Director, Regulatory Relations

cc: Service Lists R.14-08-013 and R.14-10-003
Gabe Petlin – Energy Division (copy of confidential attachment will be sent)
Robert Peterson – Energy Division (copy of confidential attachment will be sent)

Attachments

Attachment A – Candidate DER Distribution Deferral Prioritization Metrics (Public Version)

Attachment B - Candidate DER Distribution Deferral Prioritization Metrics (Confidential Version)

Attachment C – Location of Needs

Attachment D – Unit Cost of Traditional Mitigation and Preliminary Estimate of Cost-Effectiveness Cap

Attachment E – IPE DPAG Report (Public Version)

Attachment F – IPE DPAG Report (Confidential Version)[6]

Attachment G – Confidentiality Declaration

[6] Attachments to the IPE Report are large in size and will be provided upon request to PG&E and may be subject to a non-disclosure agreement.

ADVICE LETTER SUMMARY

ENERGY UTILITY

MUST BE COMPLETED BY UTILITY (Attach additional pages as needed)

Company name/CPUC Utility No.: Pacific Gas and Electric Company (ID U39E)

Utility type:

- [x] ELC
- [ ] GAS
- [ ] WATER
- [ ] PLC
- [ ] HEAT

Contact Person: Kimberly Loo
Phone #: (415)973-4587
E-mail: PGETariffs@pge.com
E-mail Disposition Notice to: KELM@pge.com

EXPLANATION OF UTILITY TYPE

ELC = Electric GAS = Gas WATER = Water
PLC = Pipeline HEAT = Heat

(Date Submitted / Received Stamp by CPUC)

Advice Letter (AL) #: 5688-E

Tier Designation: 2

Subject of AL: Request for Approval to Issue Competitive Solicitations for Distributed Energy Resource (DER) Procurement for Electric Distribution Deferral Opportunities

Keywords (choose from CPUC listing): Compliance

AL Type: [ ] Monthly [ ] Quarterly [x] Annual [ ] One-Time [ ] Other:

If AL submitted in compliance with a Commission order, indicate relevant Decision/Resolution #:
D.18-02-004

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL: No

Summarize differences between the AL and the prior withdrawn or rejected AL:

Confidential treatment requested? [x] Yes [ ] No

If yes, specification of confidential information: See Attachment G
Confidential information will be made available to appropriate parties who execute a nondisclosure agreement. Name and contact information to request nondisclosure agreement/access to confidential information: Quinn Nakayama, (415) 973-3732, QJNI@pge.com

Resolution required? [ ] Yes [x] No

Requested effective date:

No. of tariff sheets: 0

Estimated system annual revenue effect (%): N/A

Estimated system average rate effect (%): N/A

When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).

Tariff schedules affected: N/A

Service affected and changes proposed[1]: N/A

Pending advice letters that revise the same tariff sheets: N/A

[1]Discuss in AL if more space is needed.

Clear Form

Protests and all other correspondence regarding this AL are due no later than 20 days after the date of this submittal, unless otherwise authorized by the Commission, and shall be sent to:

CPUC, Energy Division Attention: Tariff Unit 505 Van Ness Avenue San Francisco, CA 94102 Email: EDTariffUnit@cpuc.ca.gov	Name: Erik Jacobson, c/o Megan Lawson Title: Director, Regulatory Relations Utility Name: Pacific Gas and Electric Company Address: 77 Beale Street, Mail Code B13U City: San Francisco, CA 94177 State: California Zip: 94177 Telephone (xxx) xxx-xxxx: (415)973-2093 Facsimile (xxx) xxx-xxxx: (415)973-3582 Email: PGETariffs@pge.com
	Name: Title: Utility Name: Address: City: State: District of Columbia Zip: Telephone (xxx) xxx-xxxx: Facsimile (xxx) xxx-xxxx: Email:

Clear Form

Advice 5688-E
November 15, 2019

Attachment A

Candidate DER Distribution Deferral Prioritization Metrics
(Public Version)

Candidate DER Distribution Deferral Prioritization Metrics (Public)

Tier	Candidate Deferral	In-Service Date	Deficiency (MW)	Prioritization Metrics		
				Cost Effectiveness	Forecast Certainty	Market Assessment
1	Alpaugh New Feeder	2022	4.4			
	Calflax Bank 2	2023	CC[1]			
	Santa Nella New Bank & Feeder	2022	9.3			
	FMC 1102	2023	0.8			
2	Camp Evers 2107	2022	0.9			
	Brentwood 2105	2022	1.2			
3	Estrella Substation	2024	19.4			
	Pueblo Bank 3	2022	23.2			
	Oceano 1106	2022	1.2			
	Rosedale 2102	2022	1.8			
	Rob Roy 2105	2022	3.0			
	Peabody 2106	2022	CC			
	Madison 2101	2022	CC			
	Martin SF H 1108	2022	1.0			
	Martin SF H 1107	2022	1.8			
	Avenal 2101	2022	CC			
	Edenvale 2108	2022	1.5			
	Dairyland 1110 New Feeder	2022	4.5			

[1] Banks and feeders with peak loads listed as "CUSTOMER CONFIDENTIAL" or "CC" were redacted due to their peak loads violating the 15-15 customer privacy rule. A 15-15 violation occurs if the load is comprised of less than 15 customers or a single customer contributes to more than 15% of the loading value.

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Attachment B

Candidate DER Distribution Deferral Prioritization Metrics
(Confidential Version)

Advice 5688-E
November 15, 2019

Attachment C

Location of Needs

Attachment C
Location of Needs

<u>Location of Candidate DIDF Solicitation Sites:</u>

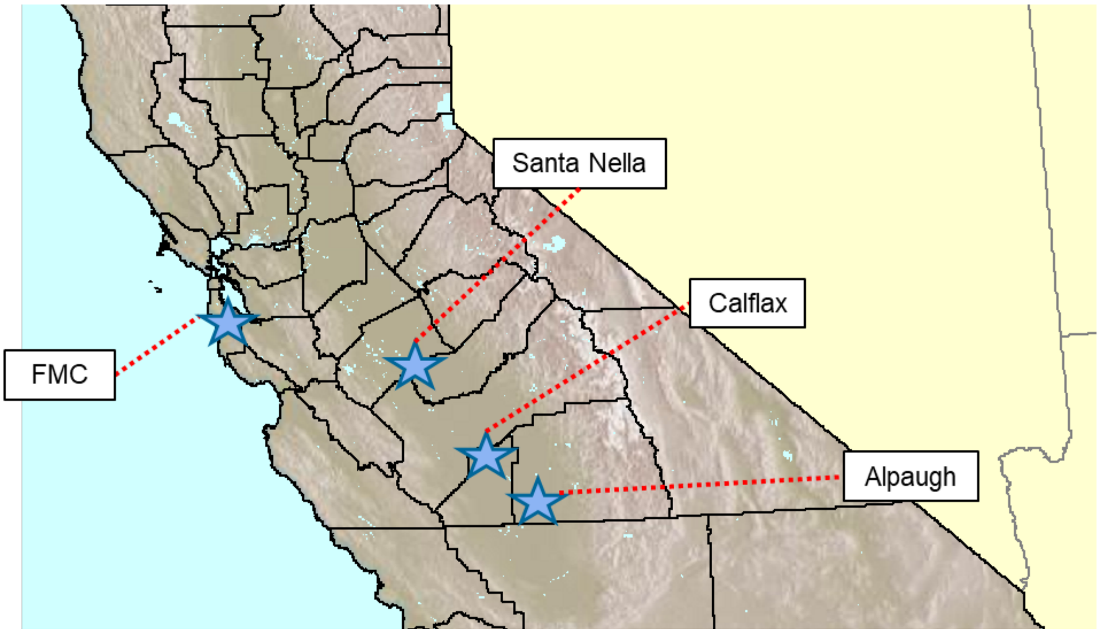

Figure 1: Map of Candidate Deferral Opportunity Locations

DISCLAIMER: Locations shown on these map images are for informational purposes only. This does not guarantee interconnection approval. This does not prevent the need for required upgrades and associated costs for interconnection.

Alpaugh Map:

Figure 2: Map of grid need location for Alpaugh New Feeder

Calflax Map:

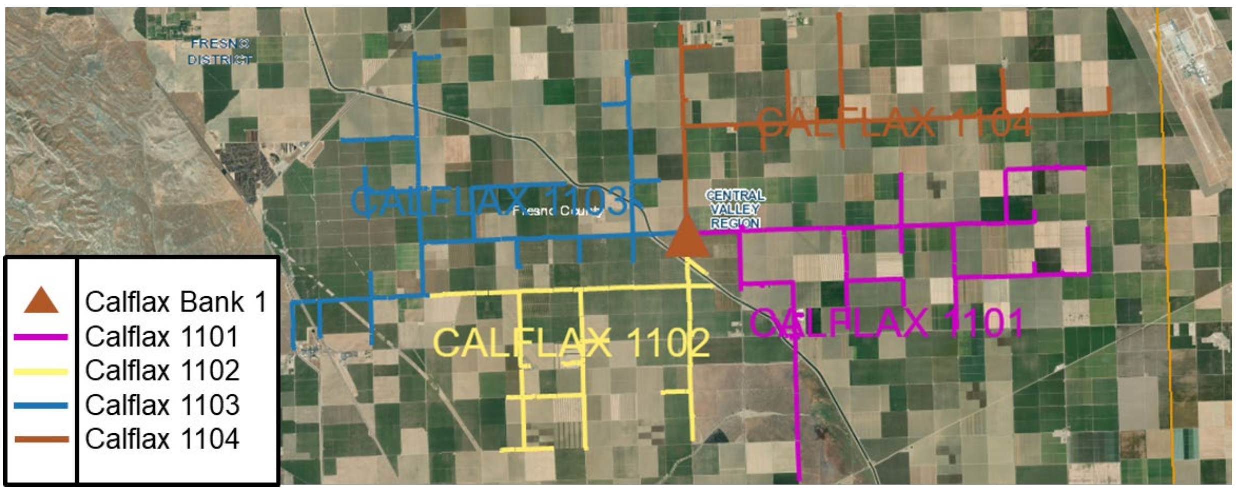

Figure 3: Map of grid need location for Calflax Bank 2

DISCLAIMER: Locations shown on these map images are for informational purposes only. This does not guarantee interconnection approval. This does not prevent the need for required upgrades and associated costs for interconnection.

Santa Nella Map:

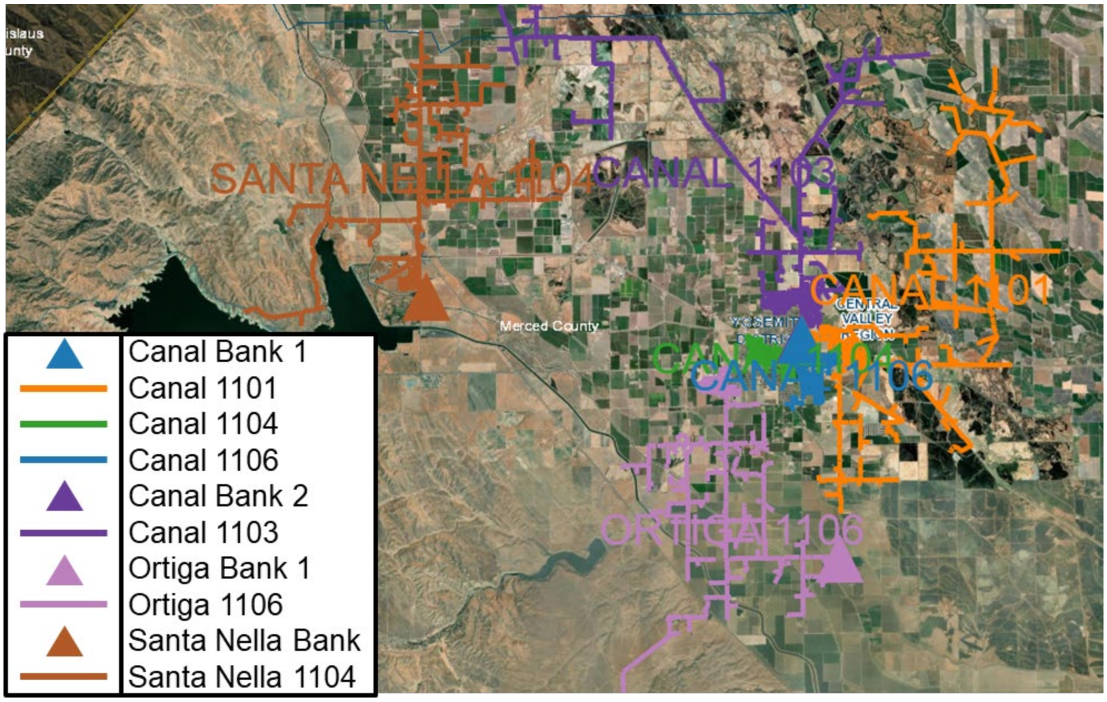

Figure 4: Map of grid need location for Santa Nella New Bank & Feeder

FMC 1102 Map:

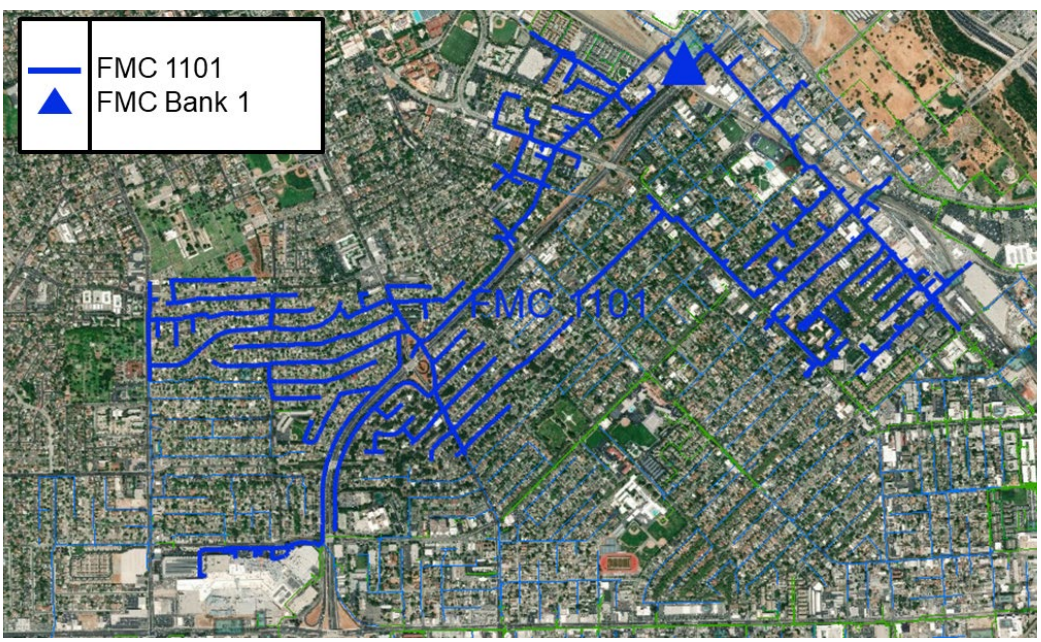

Figure 5: Map of grid need location for FMC 1102

DISCLAIMER: Locations shown on these map images are for informational purposes only. This does not guarantee interconnection approval. This does not prevent the need for required upgrades and associated costs for interconnection.

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Attachment D

Unit Cost of Traditional Mitigation and Preliminary Estimate of Cost-Effectiveness Cap

Unit Cost of Traditional Mitigation and Preliminary Estimate of Cost-Effectiveness Cap

The preliminary cost effectiveness cap is based on the indicative deferral value calculated using the Real Economic Carrying Charge (RECC) methodology as described in PG&E's Demo B final report, section 8.2[1], using the following inputs:

- Capital upgrade unit cost: See table below
- Revenue Requirement Multiplier:
  - 134.1% for substation equipment
  - 137.8% for primary feeders
- Discount Rate: 7%
- Equipment inflation: 2.5%
- O&M Inflation Rate: 2.5%
- Annual O&M of deferred upgrade as a % of upgrade cost:
  - 2.52% for new substation equipment
  - 7.48% for new primary feeder
  - 0% for replacing existing equipment
- Book life of capital asset: 46 years
- Deferral time frame: Based on deferring projects until the end of the planning window

Table 1: Preliminary Deferral Value for Candidate Deferral Opportunities

Project	Project Cost ($000s)	Deferral Time Frame	Deferral Value ($000s)
Alpaugh New Feeder	$3,600	7 years	$2,777
Calflax Bank 2	$6,070	6 years	$2,504
Santa Nella Bank 1 & New Feeder	$7,256	7 years	$3,309
FMC 1101	$1,700	6 years	$1,099

PG&E proposes to set the initial cost-effectiveness cap at the deferral value for each candidate deferral opportunity shown in Table 1 above. PG&E may revise the initial cost-effectiveness cap shown in the attachment based on additional information, including regarding incremental direct and indirect costs, that becomes available between now and contract execution.

PG&E will continue planning and designing the planned investment until CPUC approval of any executed DER deferral contracts. Charges for these activities will be subtracted from the deferral value and will be recorded appropriately for future recovery. Any revisions to the preliminary cost-effectiveness cap calculation shown in the attachment will be included in the Tier 2 advice letter requesting Commission approval of executed contracts for the DIDF.

[1] http://drpwg.org/wp-content/uploads/2016/07/R1408013-PGE-Demo-Projects-A-B-Final-Reports.pdf

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Preliminary Estimate of Administrative Costs Associated with the DIDF Solicitations

PG&E's preliminary estimate of administrative costs associated with the DIDF are based on the estimate of administrative costs for the IDER Incentive pilot approved in Resolution E-4956[2]. The actual administrative costs will be recovered via the memorandum account in PG&E's General Rate Case. The table below provides PG&E's preliminary estimate of administrative costs per candidate deferral opportunity.

Table 2: Preliminary estimate of administrative costs.

Milestone No.	Work Scope/Activity	Category	Schedule* (months are additive)	Preliminary Budget
1	CPUC Approval		___ (if decision is later, project viability and schedule may change)	
2	Develop/Administer Competitive Solicitation	Solicitation	+4 months from milestone No. 1	$1,250,000
3	CPUC Approval of Contract(s)	Solicitation Approval	+8 months from milestone 2	
4	Commissioning and Ongoing Testing and Verification of Deployed DERs	Commissioning + Ongoing Testing and Verification	+18 months from milestone 3	$500,000
5	Ongoing Project and Contract Management Costs ($100,000 per year)			$700,000*
Total				**$2,450,000***

*Assumes seven-year contract term. A contract with a six-year term would have an estimate $100,000 less.

[2] http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M235/K815/235815737.PDF

Advice 5688-E
November 15, 2019

Attachment E

IPE DPAG Report
(Public Version)

REPORT

Independent Professional Engineer PG&E 2019 GNA/DDOR Report

Public Version

Submitted to California Public Utilities Commission and PG&E

November 5, 2019

Statement of Confidentiality

The CPUC made provision for the Investor Owned Utilities to request confidentiality treatment for certain data submitted in their GNA/DDOR reports or other material provided to the IPE that is contained in this report. PG&E has designated certain data in this report to be confidential per the 15/15 rule. This confidential data has been redacted in this PUBLIC VERSION of the IPE Report in the body of the report. In addition, some documents in Appendix B which have confidential information have that confidential data redacted. The files with redacted data are highlighted in Appendix B.

In summary, this report can be distributed to any interested parties.

Contents

1 Introduction and Background

Summary of CPUC May 7, 2019 Rulemaking 14-08-013

The paragraphs that follow summarize the parts of the May 7, 2019 CPUC ruling that directly impact this report.

The CPUC directed that the IOUs shall file, in a report pursuant to their ruling, a combined Grid Needs Assessment (GNA) and Distribution Deferral Opportunity Report (DDOR) by August 15th of each year. The GNA and DDOR shall provide a characterization of circuits according to the data types and attributes described in their decision. The ruling indicated that the GNA filings should describe all types of grid needs and the processes used to determine the need. This includes all grid needs subject to CPUC jurisdiction, including all substation and sub-transmission system needs for which the deferrable project would be requested. The GNA datasets should be provided in machine-readable spreadsheets and submitted in electronic format with formal GNA filings. The IOUs are directed to explain any discrepancies between the GNA data and corresponding online maps. Additionally, the GNA should include the entire list of circuits on the distribution system, with forecasted demand, DER growth, and percent loading for each individual circuit. Additionally, the GNA should contain the Distribution per Customer Metric as ordered by D.18-02-004.

The ruling indicated that line segment and volt/var requirements only need to be identified for a two- to three-year period and that they should identify and explain these needs in the written narrative portion of the report.

The ruling continued the use and roll of an advisory group (Distribution Planning Advisory Group[1] or DPAG) and reaffirmed that the DPAG should maintain its original scope, and should remain focused on the agenda topics identified in D.18-02-004: (1) planning assumptions and grid needs reported in the GNA; (2) planned investments and candidate deferral opportunities reported in the DDOR; (3) candidate deferral prioritization; and (4) underlying technical and operational requirements for the DER alternative. The ruling further clarified that solicitation requirements will be addressed through the reform of the Competitive Solicitation Framework in R.14-10-003 (the IDER Proceeding).

The ruling continued the use of an Independent Professional Engineer (IPE). The ruling spells out the following high-level requirements for the IPE:

- Following the submission of the GNA/DDOR by the IOUs, the Independent Professional Engineer (IPE) will have 21 days (September 21, 2019) to conduct a preliminary analysis

[1] The Commission established the DPAG to consist of IOUs, Commission technical staff, an Independent Professional Engineer (IPE) technical consultant, non-market participants, and DER market providers.

to present at the DPAG meetings, which may raise additional questions for the parties and/or the IOUs.

- Following the initial round of DPAG presentations and discussions, parties will have an opportunity to submit additional comments and questions to the IPE and the IOUs by September 23, 2019. These comments will be addressed by the IPE in their final report.
- Participate in all DPAG meetings and follow up webinars.
- Prepare and provide a final IPE Report by October 21.

The ruling directs the IPE to perform its work under the direction of the Energy Division.

The ruling sets out November 15, 2019 as the deadline for a DIDF Advice Letter Filing to be filed by each IOU. RFOs for DER's that are approved by the CPUC are to be launched within 30 days of CPUC.

The ruling directed the continued use of the three-prioritization metrics previously used (Cost-Effectiveness, Forecast Certainty, and Market Assessment) and further directs the IOUs to continue to provide the LNBA value for the candidate deferral projects, and to also provide LNBA in $/MWh. The ruling also directs the IOUs to determine cost-effectiveness of deferral opportunities on a ten-year need basis for consistency and to provide more long-term certainty for DER deferral opportunities. According to the ruling what this means in practice is the deferral period should always match the length of the need period.

The Ruling goes further in defining the role of the IPE as summarized below:

The role of the IPE is to verify the assumptions and estimates that are reported in the GNA/DDOR and to provide an engineering assessment to verify that all grid needs and all distribution upgrades that can be considered for deferral have been included. To do so, the IPE should explain the data gathered and how the information provided by IOUs was verified or validated. For information that could not be verified, explain what the information gaps are.

The Ruling states that specifically, the IPE's Scope of Work should review:

- DER forecast disaggregation
- Forecasted grid needs that reflects all grid needs and all distribution upgrades that can be considered for deferral
- Timing of projects
- The cost estimates for the deferral projects so that they accurately reflect the total distribution project cost

- Application of screening metrics and processes to the deferral projects to ensure that screening is consistent with the approved methodology
- DER operational requirements for selected projects

The IPE report should also include a brief summary of issues raised by DPAG members and IOU responses, which may be collected through written comment, and recommendations on whether any distribution deferral projects should be added, removed or modified. The report shall include all data requests submitted to the IOUs and responses as attachments to the report.

Independent Professional Engineer

The California Public Utilities Commission (Commission) ruling directs Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (Utilities) to enter into a contract with an Independent Professional Engineer (IPE). The role of the IPE is as previously described.

Through a contract with Nexant, Inc., PG&E engaged Mr. Barney Speckman[2], PE, to serve as the advisory engineer (referred to as the Independent Professional Engineer (IPE)) for the GNA/DDOR process that will lead up to a PG&E filing a DIDF Advice letter on November 15, 2019. This report which meets the requirements included in the CPUC ruling was provided to PG&E in sufficient time to be included in their DIDF Advice Letter.

1.1 Services Considered within the DDOR Framework

The CPUC, in a previous decision, approved the four services proposed by the Competitive Solicitation Framework Working Group (CSFWG) and directed the utilities to consider these services in the GNA/DDOR process. The four services as described in the decision are listed below in an excerpt from the decision:

> "The following definitions for the key distribution services that distributed energy resources can provide are adopted for the Competitive Solicitation Framework:
>
> Distribution Capacity services are load-modifying or supply services that distributed energy resources provide via the dispatch of power output for generators or reduction in load that is capable of reliably and consistently reducing net loading on desired distribution infrastructure;
>
> Voltage Support services are substation and/or feeder level dynamic voltage management services provided by an individual resource and/or aggregated resources capable of dynamically correcting excursions outside voltage limits as well as supporting conservation voltage reduction strategies in coordination with utility voltage/reactive power control systems;

[2] Consistent with the CPUC decision, the contract with Nexant Inc. the firm where Mr. Speckman is employed provides for other individuals within Nexant to assist Mr. Speckman to perform the work in the IPE contract provided that these other individuals are also bound by the same confidentiality and conflict of interest requirements that Mr. Speckman is required to meet.

Reliability (back-tie) services are load-modifying or supply service 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; and

Resiliency (micro-grid) 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."

1.2 Related Proceedings

Many of the topics of interest in the GNA/DDOR process are also the subject of discussion in other CPUC proceedings. This includes, for example, the approach and method of load and DER forecasting at the circuit level which is being discussed at the Distribution Forecasting Working Group (DFWG) and issues related to what is referred to as "the double counting/double payment issue". The focus of this report is to look at the DDOR/GNA process used by the Utilities as described in meetings with the DPAG and materials provided to the DPAG recognizing that some of the issues touched upon are also being discussed in other proceedings.

1.3 Approach to Information Collection

The information reflected in this report was obtained through a number of methods including:

- Written data requests sent to PG&E regarding their planning process that lead to the needs identified in their GNA Report and the projects included in their DDOR Report. Responses from PG&E were made during follow up conference calls or in writing. A copy of written requests and written responses are included as Appendix A'
- Numerous calls with PG&E were held prior to the development of this Final Report. Calls were held on average about once a week.
- Special calls were also held to perform a Verification/Validation Walk Throughs as described later in the report.
- Participation in PG&E's DPAG meeting and its follow up DPAG Webinar
- A review of publicly available materials referred to in the discussions with PG&E or materials previously filed with the CPUC.

1.4 Report Contents

The remainder of this report includes the following sections:

- **Section 2** – Review of GNA Report which briefly discusses the contents of the PG&E GNA Report
- **Section 3** – Review of DDOR Report which briefly discusses the contents of the PG&E DDOR Report
- **Section 4** – Review of Screening and Prioritization
- **Section 5** – Review of Candidate Deferral Projects
- **Section 6** – Verification and Validation Completed which reviews the approach and results of the validation and verification performed by the IPE.
- **Section 7** – Discussion of Other Topics of Interest
- **Appendix A** – Comments Received from the DPAG Members and IOU and IPE response
- **Appendix B** – PG&E Data Requests and Responses

2 Review of GNA Report

The GNA Report submitted by PG&E is summarized below.

2.1 Scope of PG&E's GNA/DDOR Reports

The PG&E Grid Needs Assessment (GNA) Report is a written report including an Excel data base of potential grid needs on its distribution system. A corresponding DDOR Distribution Deferral Opportunity Report (DDOR) was completed summarizing the mitigation efforts required to meet the needs identified in the GNA. PG&E filed its GNA and DDOR Reports on August 15, 2019 as required by the CPUC.As a result of DPAG and IPE discussions, PG&E plans to file an update to its GNA/DDOR.

2.2 Summary of PG&E's 2019 GNA Report

The GNA covers all distribution circuits and includes circuit/segment level information which are new requirements spelled out in the CPUC Ruling. The GNA spreadsheet for PG&E included 6994 separate grid needs. The types of needs listed included the following types of information:

- **Service Required –** Capacity, Voltage Support, Reliability (back-tie), Resiliency (Microgrid);
- **Primary Driver of Grid Need –** driven by Demand Growth, Voltage or Reliability/other;
- **Rating** – Element, Rating and Units; and
- **Deficiencies –** in MW, MVAR, or Vpu and %.

2.3 Changes to GNA for 2019

The primary change in the 2019 GNA is the inclusion of an evaluation of the needs all substation, distribution feeders and feeder segments after the application of planned load transfers. This change is required by the CPUC.

Another change was the inclusion of voltage and resiliency needs in the GNA.

2.4 Discussion Related to Needs

Confidential Information

There are a number of needs whose information has been blacked out (redacted) in the GNA. These are data elements that are considered confidential entries for projects that meet the 15/15 Rule. These values are shown as "CC" or blacked out (redacted) in this report.

Discussion of Needs

A summary of needs and associated in-service or operational dates can be seen in **Table 2-1**: Summary of Grid Needs by Distribution Service and Project Type and **Table** 2-2: Summary of All Grid Needs by In-Service Date.

Of the 6994 grid needs, 6153 were for voltage support. These needs are determined from CYMDIST simulation studies and relate to feeder line sections. They do not meet the timing requirements because they are needed prior to 2022.

Table 2-1: Summary of Grid Needs by Distribution Service and Project Type

Project Type	Distribution Service				Total
	Distribution Capacity	Voltage Support	Reliability (Back-Tie)	Resiliency (Microgrid)	
Substation /Bank	59	0	10	0	**69**
Feeder	107	0	23	0	**130**
Distribution Line	631	6153	11	0	**6795**
Totals	**797**	**6153**	**44**	**0**	**6994**

Table 2-2: Summary of All Grid Needs by In-Service Date

In-Service Date						Total
2019	2020	2021	2022	2023	2024	
3418	1592	1934	28	18	4	6994

2.5 GNA - Observations, Conclusions and Recommendations

We observe that the large majority of grid needs are for line section capacity or voltage support, which are normally mitigated by solutions that can be implement quickly (in less than three years). Providing these needs by circuit line section in the GNA appears unnecessary. We believe it is reasonable to expect the utility to do this review and analysis at the circuit segment level but wonder if it is necessary to show all of the detailed results since most of the mitigation solutions do not qualify as a Candidate Deferral Opportunities because of the current timing screen. A summary of the results as opposed to providing information for each line section is suggested as an alternative with the full list available to the IPE if needed.

3 Review of DDOR Report

The following is a high-level summary of the PG&E DDOR Report.

3.1 Summary of PG&E's 2019 DDOR Report

Using the GNA as the foundation, the DDOR identifies candidate distribution deferral opportunities for potential competitive solicitation for cost-effective Distributed Energy Resource (DER) solutions to mitigate the identified distribution system needs. It also includes a description of the methodology used to prioritize candidate deferral projects for potential solicitation and procurement.

3.2 Scope of PG&E's DDOR

The PG&E DDOR is a report covering all needs identified in the GNA and includes an Excel-based workbook containing four tabs: "Planned Investment," "Candidate Deferral," "Prioritization Metrics Summary", and "Tier." The data reflected in the workbook represents a portion of PG&E's traditional infrastructure projects that contribute to the safe and reliable operation of the distribution system and serves as the baseline for evaluating opportunities for DERs to potentially defer or avoid traditional distribution system investments.

The Planned Investment-Final tab identifies 277 grid needs and since projects often fulfill multiple needs the DDOR identifies 215 associated projects that are potential DDOR opportunities. The Candidate Deferral tab identifies the 18 candidate deferral projects proposed by PG&E. The Prioritization Metrics Summary tab summarizes the individual deferral candidates and their respective metric component relative evaluations. The Tier tab provides a prioritized listing of the 18 candidate projects. The use of the Prioritization Metrics to prioritize candidate deferral projects is described in more detail later in the Report.

3.3 Discussion Related to Candidate Deferral Opportunities

A summary of the 2019 DDOR Planned Investments can be seen in **Table 3-1**: Summary of Planned Investments by Distribution Planning Region through **Table** 3-4: Summary of Planned Investments by LNBA Stage below.

Of the project types, Distribution Line (segments) projects make up 72% of the projects while feeders and substation project make up 18% and 10% respectively.

Table 3-1: Summary of Planned Investments by Distribution Planning Region

Distribution Planning Region	Project Type			Total
	Substation/Bank	Feeder	Distribution Line	
Bay Area	2	5	9	**16**
Central Coast	7	7	41	**55**
Central Valley	9	23	67	**99**
Northern	3	3	39	**45**
Totals	**21**	**38**	**156**	**215**

Distribution capacity service needs make up 60% of the service requirements.

Table 3-2: Summary of Planned Investments by Type of Service

Distribution Service				Total
Distribution Capacity	Voltage Support	Reliability (Back-Tie)	Resiliency	
129	50	36	0	215

91% of the needs have an in-service or operational date earlier than 2022.

Table 3-3: Summary of Planned Investments by In-Service Date

In-Service Date						Total
2019	2020	2021	2022	2023	2024	
77	76	44	15	2	1	215

Table 3-4: Summary of Planned Investments by LNBA Stage

LNBA Range ($/kW-yr)						Total
$0	$0-$50	$50-$100	$100-$200	$200-$500	>$500	
0	104	23	19	9	10	165
LNBA Range ($/Vpu-yr)						Total
$0	$0-$0.50	$0.50-$1	$1-$2	$2-$5	>$5	
0	17	26	5	0	2	50

3.4 DDOR – Observations, Conclusions and Recommendations

We observe that the majority of the projects required to mitigate the GNA are capacity related for distribution lines with an in-service date earlier than 2022. This is an expected outcome based upon our experience.

4 Review of Screening and Prioritization

4.1 Project Screens

This section contains a discussion of the screens PG&E used to develop its candidate deferral project list. The first screen is the Technical Screen which is intended to identify all grid needs that could be potentially mitigated by DERS with one of the four distribution services adopted by D.16-12-036, specifically Capacity, Voltage Support, Reliability (Back-Tie) and Resiliency (Microgrids).

The second screen is the Timing Screen which is intended to ensure cost-effective DER solutions can be procured and implemented with sufficient time to fully deploy and begin commercial operation in advance of the forecast need date. For this DDOR, a 2022 or later in-service date is considered as adequate lead time. Since the GNA needs analysis covers the years 2019 to 2023, the timing screen eliminates all projects other than those with in-service dates starting in 2022 and 2023. The required in-service dates are developed as part of the distribution planning process that includes load and DER forecasting at the system level and then disaggregation to the circuit level followed by need determination. This process is described in detail in the GNA/DDOR reports and discussed in Section 6 – Verification and Validation.

As discussed later in Section 6, the technical screening is a continuous process and not performed at one point in time. Therefore, the number of projects screened out because of technical concerns is not available. However, for the 215 projects that meet the technical requirements as a potential candidate deferral opportunity, only 18 projects have in-service or operational dates of 2022 or later.

4.2 Project Prioritization

This section contains a discussion of the prioritization process used by PG&E to prioritize its candidate deferral projects and a discussion of the various metrics PG&E used in that process.

PG&E used three prioritization metrics – Cost-effectiveness, Forecast Certainty and Market Assessment. These metrics are consistent with the guidance provided by the CPUC including the use of an LNBA/kWh-yr. metric as a component of the Cost Effectiveness metric. The application of these three metrics is demonstrated in the final PG&E project prioritization presented to the DPAG at PG&E's DPAG Webinar which is shown in **Table 4-1**: DDOR Candidate Deferral Summary on the following page.

It should be noted PG&E does not use a quantitative assessment but rather uses a qualitative evaluation/prioritization methodology for comparing projects to each other.

Table 4-1: DDOR Candidate Deferral Summary

Tier	Candidate Deferral	In-Service Date	Deficiency (MW)	Prioritization Metrics		
				Cost Effectiveness	Forecast Certainty	Market Assessment
1	Alpaugh New Feeder	2022	4.4			
	Calflax Bank 2	2023	CC			
	Santa Nella New Bank & Feeder	2022	9.3			
2	Camp Evers 2107	2022	0.9			
	FMC 1102	2023	0.8			
	Brentwood 2105	2022	1.2			
3	Estrella Substation	2024	19.4			
	Pueblo Bank 3	2022	23.2			
	Oceano 1106	2022	1.2			
	Rosedale 2102	2022	1.8			
	Rob Roy 2105	2022	3.0			
	Peabody 2106	2022	CC			
	Madison 2101	2022	CC			
	Martin SF H 1108	2022	1.0			
	Martin SF H 1107	2022	1.8			
	Avenal 2101	2022	CC			
	Edenvale 2108	2022	1.5			
	Dairyland 1110 New Feeder	2022	4.5			

The evaluation of the metrics is used qualitatively by PG&E to place Candidate Deferral Opportunities into tiers based upon their relative rankings using the three metrics. The qualitative rankings also include the engineering judgement of distribution planners.

The relative ranking of each candidate opportunity is identified in a 4-tier prioritization system with a color code as shown in **Table 4-2**: Tier Prioritization System. Note there are no projects in Tier 4, labelled "Considered Elsewhere".

Table 4-2: Tier Prioritization System

Tier	Color Designation	Definition
1		Relatively High Ranking
2		Relatively Moderate Ranking
3		Relatively Low Ranking
4		Considered Elsewhere

The development of the three-prioritization metrics is based on the evaluation of components of each of the three metrics as discussed below. **Table 4-3**: Basis for Prioritization Metrics identifies the metric subcomponents and basis for the metric evaluations.

Table 4-3: Basis for Prioritization Metrics

Tier	Candidate Deferral	Cost Effectiveness			Forecast Certainty			Market Assessment				
		Unit Cost ($k)	LNBA ($/kW-yr)	LNBA ($/MWh/yr)	In-Service Date	SCADA Avail. (Y/N)	Cust-omers	Real Time (RT) or Day Ahead (DA)	Days/ Year	# of Grid Needs	Hours/ Call	Over-capacity (%)
1	Alpaugh New Feeder	$3,600	$89	$88	2022	Y	2650	DA	113	1	9	38%
	Calflax Bank 2	$6,070	$88	$60	2023	Y	228	DA	CC	1	CC	CC
	Santa Nella New Bank & Feeder	$7,256	$55	$78	2022	Y	973	DA	122	4	7	36%
2	Camp Evers 2107	$1,720	$202	$2,100	2022	Y	6370	RT+Islanding	8	1	12	3%
	FMC 1102	$1,700	$232	$4,830	2023	Y	3422	RT	4	1	12	4%
	Brentwood 2105	$640	$59	$612	2022	Y	2841	RT+Islanding	8	1	12	6%
3	Estrella Substation	$18,500	$65	$234	2024	Y	225	RT+Islanding	122	7	48	39%
	Pueblo Bank 3	$6,936	$21	$110	2022	Y	9952	RT	8	1	24	52%
	Oceano 1106	$425	$18	$64	2022	Y	6811	RT+Islanding	12	1	24	8%
	Rosedale 2102	$400	$24	$84	2022	Y	1378	RT	12	1	24	9%
	Rob Roy 2105	$500	$18	$63	2022	Y	8056	RT+Islanding	12	1	24	13%
	Peabody 2106	$390	$8	$28	2022	Y	2845	RT+Islanding	CC	1	CC	CC
	Madison 2101	$105	$13	$45	2022	Y	2068	RT+Islanding	CC	1	CC	CC
	Martin SF H 1108	$180	$9	$33	2022	Y	6716	RT+Islanding	12	1	24	8%
	Martin SF H 1107	$150	$4	$15	2022	Y	7090	RT+Islanding	12	1	24	18%
	Avenal 2101	$65	$6	$21	2022	Y	1948	RT+Islanding	CC	1	CC	CC
	Edenvale 2108	$95	$7	$24	2022	Y	6630	RT+Islanding	12	1	24	7%
	Dairyland 1110 New Feeder	$3,887	$96	$24	2022	Y	518	DA	168	1	24	34%

The Cost Effectiveness metric is intended to provide a relative indication of how likely DER resources can cost effectively defer a planned investment. This metric has three components, Unit Costs, LNBA $/KW-yr. and LNBA $/MWh-yr. The Unit Costs are the estimated project capital costs at the time of the report. This topic is discussed in Section 6.3. The projects with larger unit or project costs for traditional solutions are ranked higher than others. The LNBA-related metrics are developed by taking the LNBA value for this project and dividing that value by the maximum kW need during the deferral period and the maximum kWh-yr. need during any one year of need. The overall evaluation is tempered with engineering judgement based on experience with lessons learned from PG&E's DRP Demonstration Projects C and D RFOs.

High tiered projects under the Cost Effectiveness Metric are characterized by:

- High Unit Cost of Traditional solution;
- High LNBA ($/kW-year);
- High converted LNBA per MWh of deferral ($/Megawatt-hour (MWH)-year); and
- Judgement based on experience with previous pilots.

The Forecast Certainty Metric is intended to give a relative indication of the certainty of the forecast grid need. This metric also contains three components, Forecasted Need (year), SCADA Available, and Customers on Asset. The Forecasted Need identifies the year the need is required which is developed in the distribution planning process (utilizing a number of tools including LoadSEER and CYMDIST). PG&E considers needs in later years as having more uncertainty. PG&E places high importance on the ability to the use SCADA to validate the existing load and therefore a strong foundation for the forecast. This component is given the most weight in the Forecast Certainty Metric. All candidate opportunities in this DDOR had SCADA data available, so this component did not impact the prioritization process results. The number of customers causing the need is assumed to decrease the variance in the dependence of the need per customer. This is based on the belief higher the number of customers, the greater the certainty of the forecast. Again, this evaluation is tempered with engineering judgment from PG&E distribution planners who are familiar with the development of future projects and weather and temperature patterns that may impact load, especially in agricultural areas.

High tiered projects under the Forecast Certainty Metric are characterized by:

- Nearer term need (2022 vs. 2023);
- Availability of Supervisory Control and Data Acquisition (SCADA) data recordings;
- Higher number of customers causing the need; and
- Judgement based on engineering knowledge of the area.

The third metric Market Assessment is intended to give a relative indication of how likely DER resources can be sourced to successfully meet the DER distribution service requirements. This metric has five components, Real Time or Day Ahead Notification, Days/Year, Number of Grid Needs, Hours Per Call and Overcapacity.

Real Time projects are identified as either just Real Time, where capacity is required in support of PG&E service, and as Real-Time-Islanding, where the capacity is required and must be maintained independent of PG&E service.

Projects with Day Ahead requirements are given a higher ranking than projects with Real Time requirements, because it is believed some developers may view a Real Time five-minute dispatch notice and potential islanding requirements to be more difficult and costly to achieve in practice and likely to impact potential revenue streams.

The Days/Year component is listed as one component. However, it is evaluated differently for Real Time and Day Ahead projects. Day Ahead projects are not compared with Real Time projects for the evaluation of this component. In other words, for this component only, all projects are not ranked against each other. Real Time projects are ranked against each other and Day Ahead projects are ranked against each other. The reason for this segregation is the uncertainty of the Real Time Days/Year as compared to the Day Ahead Days/Year value. The use of this component is somewhat difficult to follow and is being reconsidered by PG&E.

For the Number of Grid Needs component, a project with fewer needs (i.e. a project that has fewer circuits with needs) is given a higher evaluation rating than a project with many circuits that have needs. The reason for this is implementing DER solutions for few locations will be easier than implementing DER for many locations.

The Hours Per Call component addresses the duration of the DER service requirement. For a project with one element this value would be the project's DER duration need as determined in the planning process. For projects with multiple needs the value would be the maximum duration of any of the elements included in the project. Projects with lower duration are weighted higher (better) than those with longer needs.

Finally, the Overcapacity component is intended to evaluate the penetration of DER required to meet the need. This value is calculated as the % overload of the need over the five-year planning period. If there are multiple needs, the maximum need, not the sum of the needs, is used for this calculation. According to PG&E, the lower the overcapacity the more likely a DER solution would be successful. There was a discussion about using actual MW values as opposed to percentage and PG&E believes the percent penetration is more meaningful. As with the other metrics, engineering judgement and lessons learned from the previous pilots is also considered.

High tiered projects under the Market Assessment Metric are characterized by:

- Only Day Ahead, rather than Real Time, operational requirements;
- Low number of electric facilities experiencing grid needs in a project;
- Fewer number of days needed per year; and
- Lower ratio of overload (lower penetration needed); and Judgement based on experience with pilots.

Numerical values are not used in the individual metric component evaluation; instead PG&E segregates the values into relatively high/medium/low groups which are then identified by the associated color previously described.

The final metric prioritization decision is a qualitative evaluation of the individual metric components. Under PG&E's methodology, if all components are identified as blue (relatively high ranking), the overall prioritization for that metric is blue. However, in practice the worst individual component ranking is used for the overall ranking. So, two blue and one purple component evaluation is generally ranked as purple overall for that metric. The purpose of is process is to primarily highlight potential problems or red flags.

4.2.1 Project Prioritization - Observations Conclusions and Recommendations

- We observe PG&E uses a relative ranking of projects to avoid suggesting one project or another will be successful. It is intended to be an evaluation of relative success when compared to other candidate projects. This methodology could be improved with explanations provided for additional transparency along with the relative ranking. This includes providing the relative weighing of the individual components of each metric.

- The prioritization process varies greatly among the IOUs; with each IOU having some good ideas and approaches. We recommend that the three IOUs consider standardizing, as much as possible, on the use of metrics for the benefit of the DPAG and others who review the recommendations and that the IOUs strive to use quantified metrics where ever possible.

- We observe that in our IPE Report of 2018 that we suggested the potential use of four cost effectiveness metrics – 1) based upon Costs/kW, 2) based upon Costs/kWh-day and 3) Costs /kWh-yr. 4) Maximum number of days of need per year. The rationale for that recommendation is included in the report which was filed with PG&E's advice letter filing. For convenience, that report can be found at the following link which provides access to the 2018 PG&E Advice Letter Filing which includes as an attachment the IPE Report. https://www.pge.com/tariffs/assets/pdf/adviceletter/ELEC_5435-E.pdf

- In that report we indicated that a metric based upon Costs/kWhr-day is one of the best metrics. We continue to believe that and recommend that LNBA/kWhr-day be used in place of LNBA/kWhr-year currently in use. We recommend that because we believe there is no perfect metric and some metrics are more accurate with respect to one technology than another. We believe that a LNBA/kWhr-day metric best captures the cost effectiveness of battery projects which appear to often be very commonly bid DER and very competitive and often are the wining technology.

  The LNBA/kWhr-year metric is a metric that is a good proxy for costs for technologies that have the potential to increase in cost based upon the number of times they are dispatched. This includes most notably LMDR.

- We observe PG&E is in the process of reviewing the metric prioritization as a result of the DPAG meetings. As of this preparation of this report that reprioritization has not be completed.

- We observe that the overall cost effectiveness prioritization approach used by all of the IOUs (consistent with direction by the CPUC) is based upon ranking projects based upon various cost metrics. Given what is happening in the industry with dispatchable DERs striving to capture value by stacking use cases, cost effectiveness is likely to be increasingly impacted by what other use cases can be implemented by a DER in addition to the project deferral use case. At some point in the not too distant future we believe that “value staking” will impact the true cost effectiveness of potential DERs and thus will need to be considered in the prioritization process metrics. We see from some of the questions by DPAG members that they are actively considering other use cases as they review deferral candidate projects.

A review of the results of the PG&E prioritization process and the IPE’s recommendations are included in the next section.

5 Candidate Deferral Projects

In this section we review the projects PG&E initially recommended for inclusion in Tiers 1-2 plus Estrella. It is noted that PG&E recommended 4 tiers however there are no projects recommended for Tier 4 (Already Sourced Elsewhere). The discussion in this section will review the ranking of projects presented at the PG&E DPAG Webinar which included some updated material from the PGE DPAG meeting.

We believe the Cost Effectiveness category, in general, is somewhat different than the other two categories. If there are insufficient funds/budget[3] to develop and operate a DER solution that is cost effective (one that results in a bid that is below the cost cap) then the other two categories become less important. In other words, the Cost-effectiveness category is somewhat of a threshold category. For this reason, we have examined PG&E's candidate projects and their proposed prioritization from the Cost Effectiveness metric perspective in more detail than the other two categories, although the other two categories remain critical to the overall prioritization process

It must be noted however, if a project looks favorable on a cost-effectiveness basis, it does not mean it should automatically receive an overall high ranking because there may be significant issues/red flags in the other two prioritization categories that could result in a lower overall ranking.

5.1 Candidate Deferral Projects – Observations, Conclusions and Recommendations

- If we examine the projects currently recommended for Tier 1 and Tier 2 from a Cost Effectiveness and LNBA/MWh-year perspective we see from the following table the Tier 1 projects are the relatively highest ranked projects from a Unit Cost Perspective Metric while the Tier 2 projects rank higher from a LNBA/MWhr-year perspective.

  We see from PG&E's data that the LNBA/MWhr-year values for the Tier 1 and Tier 2 projects that the FMC 1102 projects has the highest (best) LNBA/MWhr-year value. If we look at the ratio of the LNBA/MWhr values of all projects in Tiers 1 and 2 to the LNBA/MWhr value for the FMC 1102 project (shown in the far-right column), we see this ratio varies considerably and decreases as we proceed down the list of ranked projects. This ratio can be considered a relative proxy for the amount of money that can be spent on a DER solution compared to the money that can be spent for the FMC project and still be under the cost cap and thus be cost-effective compared to the traditional wires

[3] Funds/budget in this instance can also be thought of as head room – economic space in which to develop a project and still be under the cost cap.

solution. If, for example, we look at the Camp Evers ration value of 0.435 (or 43.5%), it suggests the amount of money that can be spent per MWhr-year on the DER solution for the Camp Evers project is 43% of what can be spent on DERs per MWhr-year to avoid the FMC 1102 project.

As we see in **Table 5-1**: Tier Rankings and Ratios, this ratio drops off to less than 2% for all of the Tier 1 projects. This suggests it will be substantially more difficult for a DER project to beat some of the Tier 1 wires project than the FMC 1102 project.

Table 5-1: Tier Rankings and Ratios

Project	Tier	Ranking by Unit Cost	LNBA/MWhr-year Ranking (compared to listed projects)	LNBA/MWhr-year Ratio to FMC 1102
Alpaugh New Feeder	1	4	6	0.018
Calflax Bank 2	1	2	7	0.012
Santa Nella New Bank and Feeder	1	3	11	0.016
Camp Evers 2107	2	5	2	0.435
FMC 1102	2	6	1	1.000
Brentwood 2106	2	7	3	0.127
Estrella Sub	3	1	4	0.048

- We observe from the previous discussion that another way to look at the cost effectiveness metric is to look at the ratio of the LNBA/MWhr values to the LNBA/MWhr value for the project with the greatest LNBA/MWhr-year value. This will provide an additional cost-effective comparison of projects. Note we have used the LNB/MWhr-year values because they are in the PG&E materials but as indicated elsewhere we believe that the LNBA/MWhr-day (maximum energy needed in any day or call) is a superior metric to use. Use of ratios like these gives additional insight to simple ranking of projects
- PG&E is considering moving one Tier 2 project to Tier 1 to gain experience with a Real Time (RT) (without islanding) project. Based upon its strong cost effectiveness metric

and the fact that it does not require an islanding function to be included (unlike the other two Tier 2 Real Time Projects), we recommend that the RT project to be moved to Tier 1 be the FMC 1102 project. We do not recommend any other Tier 1 changes.

Estrella Project

The Estrella project is a distribution project that is related to a transmission project whose request to the CPUC for a Permit to Construct (PTC) pursuant to General Order 131-D is currently being reviewed at the CPUC (Application A.17-01-023). The review includes a CEQA environmental review process[4]. The transmission project has been approved by the CAISO in their 2013-2014 transmission planning process and involves the construction of a new 230/70/21-kV substation (Estrella) with transmission facilities to be owned by PG&E and a third party.

The proposed distribution component of the Estrella project would be constructed partially within the footprint of the new Estrella Substation that is being considered in the PTC/CEQA proceedings. The distribution project includes equipment to be located within the substation (breakers, transformer, switchgear, etc.) and equipment outside the substation (overhead and underground conductors, etc.). Since the distribution project would be constructed within the substation footprint of the Estrella Substation its in-service date is predicated on the regulatory approval and construction of the transmission project.

The PTC/CEQA proceedings are expected to be completed to allow, at the earliest, an in-service date of 2024 for the distribution project assuming it is constructed at the same time as the transmission project, rather than after the transmission project as currently planned in the PTC/CEQA proceeding. However regulatory proceeding delays may delay the in-service date beyond 2024. The Estrella Substation project, because it is a transmission project, is not being considered in the DIDF process.

The proposed distribution project is included in the current DIDF process and proposes to provide additional distribution capacity in the area as well as provide for reliability service in the event of planned or unplanned outage of transmission and/or distribution facilities. The Estrella project includes 7 needs/benefits. The seven components are listed in the following slide that was presented to the DPAG at PG&E’s DPAG Webinar. Note that PG&E made some changes in the parameters of the Estrella components/needs which were also presented at its Webinar.

[4] See https://www.cpuc.ca.gov/environment/info/horizonh2o/estrella/index.html

Estrella DER Requirements

		Expected performance and operational requirements								
Tier	Candidate Deferral Opportunity	GNA Facility Name	Distribution Service Required	Real Time (RA) or Day Ahead (DA)	Grid Need	Grid Need Unit	Month	Calls/ Year	Hours	Duration (Hours)
3	Estrella Substation	PASO ROBLES 1104	Capacity	DA	1.2	MW	Jul-Aug	21	2PM-10PM	8
		SAN MIGUEL BANK 1	Capacity	DA	3.6	MW	Jul-Sep	122	6AM-10PM	9
		TEMPLETON BANK 3	Capacity	DA	1.1	MW	Jul-Aug	23	12PM-3PM	3
		Cholame Between X14 and R96	Reliability / Other	RT + Islanding	1.5	MW	Apr-Oct	8	12AM-12AM	4
		Cholame Sub DA	Reliability / Other	DA	3.5	MW	Apr-Oct	1	12AM-12AM	48
		Cholame Sub RT	Reliability / Other	RT + Islanding		MW	Apr-Oct	8	12AM-12AM	24
		L/S R78 - Templeton 2109	Reliability / Other	RT + Islanding	8.5	MW	Apr-Oct	8	12AM-12AM	4

The Paso Robles 1104, San Miguel Bank 1 and Templeton Bank 3 require capacity service and are designated as Day Ahead. The other rows listed in the table above are reliability benefits that would result from the construction of the Estrella Substation distribution project. They are listed as driven by Reliability/Other and include Cholame Between X14 (RT and Islanding), Cholame Sub DA (DA for planned outages), Cholame Sub RT (RT for unplanned outages and Islanding) and L/S R78-Templeton 2109 (RT for unplanned outage and Islanding). This results in a project with a mix of capacity and reliability components/needs and a mix of Day Ahead and Real Time requirements.

In the prioritization process PG&E has proposed that Estrella be included in Tier 3. The reasons for that ranking is due to red flags for - 1) In service date (2024), 2) RT plus Islanding requirement, 3) number of grid needs (7), 4) hours/Call (48) and purple flags for 1) LNBA/kW-yr, 2) Customers (225), 3) Days of need per year (122) and Over-capacity (39%).

PG&E was requested by the Energy Division to analyze a hypothetical project that did not include the four Reliability/Other need/benefit components. We understand that this would leave just the three capacity needs in the consideration. PG&E presented the results of their hypothetical analysis at the PG&E DPAG Webinar. The following two slides show the results of the hypothetical analysis including PG&E's recommendation that under the hypothetical analysis they would propose that Estrella be placed in Tier 2.

From the hypothetical analysis we see that there are improvements in the prioritization due to several factors including improvements to the LNBA metrics, elimination of the RT and Islanding requirement, reduction in the number of grid needs and the shortening of the Hours/Call. The one remaining red flag is the In-Service date of 2024. This date is beyond the GNA planning period of 2019-2023 and we understand is based upon the earliest likely construction date for the new Estrella Substation (including the distribution facilities) which is tied to the PTC/CEQA completion date. There remain several purple flags for 1) Days per year, 2) Number of grid needs, 3) Hours per call and 4) Over-capacity (21%).

Normally an in-service date of 2024 (one year beyond the planning period) would raise the question of whether this project should be reviewed in the next DIDF cycle when loads and needs are more certain. However, this date is different than most other in-service dates in that it is driven by when the solution can be put in place and not when the date of first need that is being addressed. We understand that the first need dates for the three capacity components of the project are all before 2024.

Hypothetical Estrella – Prioritization Metrics

Tier	Candidate Deferral	In-Service Date	Deficiency (MW)	Prioritization Metrics		
				Cost Effectiveness	Forecast Certainty	Market Assessment
1	Alpaugh New Feeder	2022	4.4			
	Calflax Bank 2	2023	CC			
	Santa Nella New Bank & Feeder	2022	9.3			
2	Camp Evers 2107	2022	0.9			
	FMC 1102	2023	0.8			
	Brentwood 2105	2022	1.2			
	Estrella Substation (hypothetical)	2024	5.9			
3	Pueblo Bank 3	2022	23.2			
	Oceano 1106	2022	1.2			
	Rosedale 2102	2022	1.8			
	Rob Roy 2105	2022	3.0			
	Peabody 2106	2022	CC			
	Madison 2101	2022	CC			
	Martin SF H 1108	2022	1.0			
	Martin SF H 1107	2022	1.8			
	Avenal 2101	2022	CC			
	Edenvale 2108	2022	1.5			
	Dairyland 1110 New Feeder	2022	4.5			

Hypothetical Estrella – Basis for Prioritization Metrics

Tier	Candidate Deferral	Cost Effectiveness			Forecast Certainty			Market Assessment				
		Unit Cost ($k)	LNBA ($/kW-yr)	LNBA ($/MWh/yr)	In-Service Date	SCADA Avail. (Y/N)	Cust-omers	Real Time (RT) or Day Ahead (DA)	Days/ Year	# of Grid Needs	Hours/ Call	Over-capacity (%)
1	Alpaugh New Feeder	$3,600	$89	$88	2022	Y	2650	DA	113	1	9	38%
1	Calflax Bank 2	$6,070	$88	$60	2023	Y	228	DA	CC	1	CC	CC
1	Santa Nella New Bank & Feeder	$7,256	$55	$78	2022	Y	973	DA	122	4	7	36%
2	Camp Evers 2107	$1,720	$202	$2,100	2022	Y	6370	RT+Islanding	8	1	12	3%
2	FMC 1102	$1,700	$232	$4,830	2023	Y	3422	RT	4	1	12	4%
2	Brentwood 2105	$640	$59	$612	2022	Y	2841	RT+Islanding	8	1	12	6%
2	Estrella Substation (hypothetical)	$18,500	$209	$293	2024	Y	2738	DA	122	3	9	21%
3	Pueblo Bank 3	$6,936	$21	$110	2022	Y	9952	RT	8	1	24	52%
3	Oceano 1106	$425	$18	$64	2022	Y	6811	RT+Islanding	12	1	24	8%
3	Rosedale 2102	$400	$24	$84	2022	Y	1378	RT	12	1	24	9%
3	Rob Roy 2105	$500	$18	$63	2022	Y	8056	RT+Islanding	12	1	24	13%
3	Peabody 2106	$390	$8	$28	2022	Y	2845	RT+Islanding	CC	1	CC	CC
3	Madison 2101	$105	$13	$45	2022	Y	2068	RT+Islanding	CC	1	CC	CC
3	Martin SF H 1108	$180	$9	$33	2022	Y	6716	RT+Islanding	12	1	24	8%
3	Martin SF H 1107	$150	$4	$15	2022	Y	7090	RT+Islanding	12	1	24	18%
3	Avenal 2101	$65	$6	$21	2022	Y	1948	RT+Islanding	CC	1	CC	CC
3	Edenvale 2108	$95	$7	$24	2022	Y	6630	RT+Islanding	12	1	24	7%
3	Dairyland 1110 New Feeder	$3,887	$96	$24	2022	Y	518	DA	168	1	24	34%

It is clear from the initial analysis that with the combined project (capacity and reliability) as proposed there are several red flags and additional purple flags that suggest that the project may not be a strong candidate for Tier 1. It is also clear that under the hypothetical project that does not include the four reliability needs/benefits that the ranking improves substantially with one red flag remaining (In-Service date of 2024).

The reliability components of the project all provide improved customer reliability under outage conditions – unplanned in three instances and planned in the fourth (Cholame Sub DA). Two provide improved reliability for outages of distribution facilities and two for transmission facilities (Cholame Sub DA and Cholame Sub RT).

As noted in past DIDF IPE reports, these types of improvements, that are essentially improved back tie capability, can provide incremental customer benefits depending upon the specific circumstances of each project. We stated that back-tie capability may be an important benefit of a traditional project but it should not be assumed to be the case for every capacity project. We recommended that review of back-tie benefits be determined on a case by case basis.

As this report was being finalized, PG&E provided responses to Energy Division questions that provided a narrative regarding the specific benefits associated with these increased back-tie capabilities. There was not ample time to review this narrative and to fully understand the implications which would require examining detailed circuit drawings and data for the current and proposed circuits being impacted by the project.

We also understand that PG&E is concerned about the potential for delaying the PTC/CEQA process due to DIDF. According to the Energy Division they believe it is not clear at this time if this concern has merit[5].

We recommend that the consideration of the Estrella distribution project within the DIDF be continued and that to support that objective the consideration be put on a different timeline than the PG&E recommended Tier 1 projects. We recommend that this continuation be completed quickly. The following questions should be further considered:

1. Do the reliability benefits of the project represent a tangible/substantial improvement in customer reliability given the specifics of the current and proposed distribution system in the area and relative to similarly situated systems in PG&E's service territory? This is essentially examining the back-tie benefits on a case by case basis.
2. What steps could be taken to address capacity needs that are predicted to occur prior to the in-service date of 2024? If implemented, how would they affect the potential longer term solutions?
3. In view of the answers to Q 1 and 2, is the combined project the best way to meet the high priority needs of the distribution systems in the area? Is it possible to achieve the same results by separating out the reliability components from the capacity components and developing two, incremental solutions that could allow for a cost-effective deferral of the planned $18.5 million distribution investment??

We believe that other DPAG stakeholders would benefit from the additional information developed during this continuation of the consideration of the Estrella project within the DIDF.

[5] According to the July 14, 2017 Ruling for that proceeding (A.17-01-023), the scope of issues and Prehearing Conference will be set after the CEQA Draft Environmental Impact Report is circulated. This report has not yet been circulated, but the Draft Alternatives Screening Report includes a DER-based alternative for the distribution need identified in the PG&E 2019 GNA/DDOR. The CEQA document will not decide on the outcome of that proceeding. It would simply identify the potential DER alternative and considered its environmental impacts in comparison to the traditional, wired solution proposed by PG&E. It remains unclear to Energy Division staff that there is any potential for delay to proceeding A.17-01-023 due to Estrella consideration in the DIDF process.

6 Verification and Validation Approach and Results

In this section we discuss the verification and validation approach used and the results. As indicated earlier the CPUC May Ruling spelled out several areas that the IPE should validate. These include the following:

- DER forecast disaggregation
- Forecasted grid needs that reflects all grid needs and all distribution upgrades that can be considered for deferral
- Timing of projects
- The cost estimates for the deferral projects so that they accurately reflect the total distribution project cost
- Application of screening metrics and processes to the deferral projects to ensure that screening is consistent with the approved methodology
- DER operational requirements for selected projects

We subsequently added two areas to the above listed scope that we felt needed to be included in order the complete the above scope:

- **Load growth disaggregation** – which is needed to determine load growth which is necessary to determine the need and timing of projects
- **Starting point load with adjustments to reflect one in ten-year planning criteria** – which is needed to develop the overall net load forecast which is used to determine whether there is a need

We have organized these eight areas into seven verification and validation areas for discussion below.

6.1 Load and DER disaggregation and Development of Project Needs

Approach

The approach used to verify and validate these results is shown in **Figure 6-1**: System Verification and Validationand **Figure** 6-2: Circuit Level Verification and Validation on the following page.

Figure 6-1: System Verification and Validation

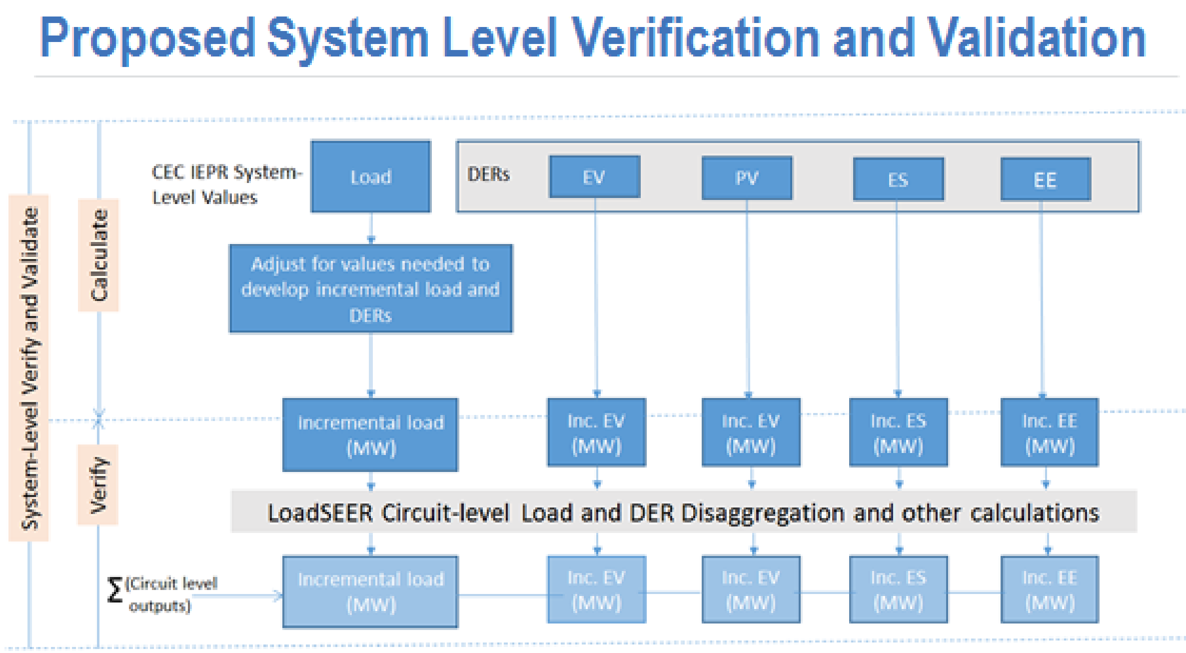
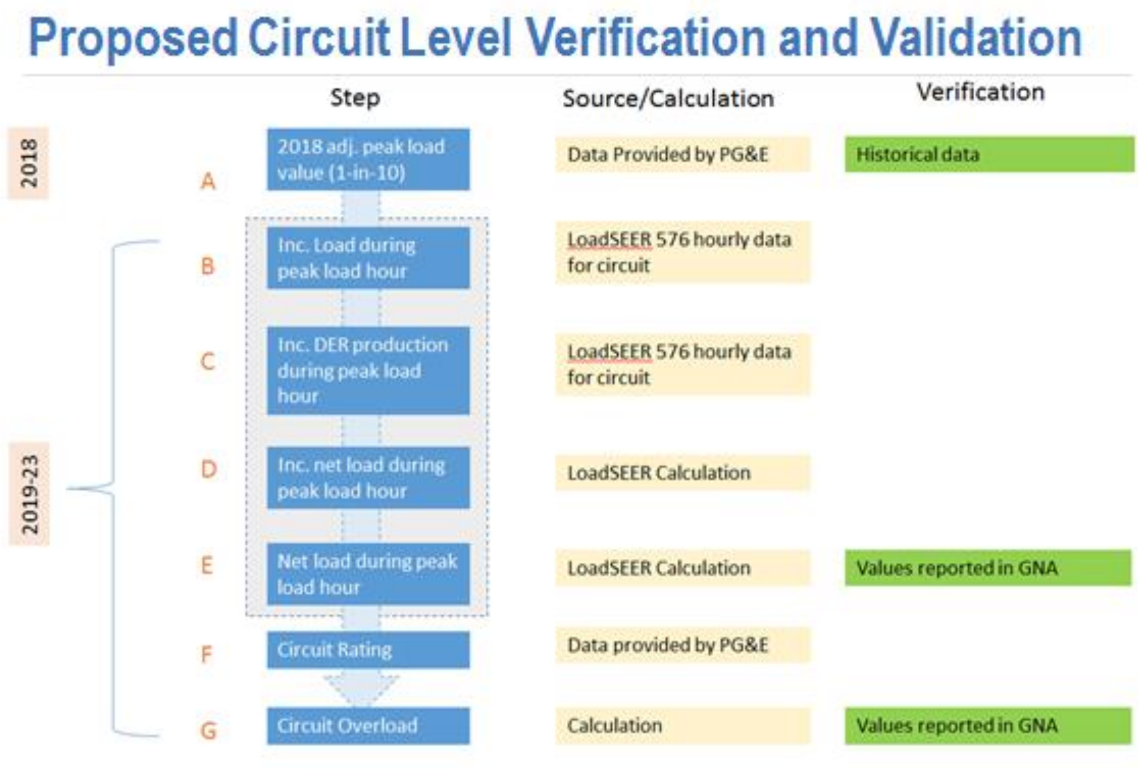


Figure 6-2: Circuit Level Verification and Validation



The review includes a system level review and a circuit level review. The system level review includes:

- The review of the use of the CEC IEPR data to develop top-down load and load and DER growth forecasts for the planning period;
- This review of CED IEPR data adjustments for such items as transmission customer loads and electric vehicle and photovoltaic forecasts.
- It also includes a check of the output results of the disaggregation of load and DERs to see if the aggregate of the outputs at the circuit level (summation of all circuit values) match the input values developed from the CEC IEPR.
- The review performs a number of checks at the individual circuit level for selected circuits. The review checks to see whether the disaggregated load and DERs when integrated, results in the values that are included in the GNA/DDOR reports.

6.1.1 System Level Review

Results

The system level check included reviewing a post processing of the CEC forecast which includes peak load and energy forecasts prior to disaggregation. This is shown on the spreadsheet in **Figure 6-3**: Peak and Energy Forecasts Based on CED 2017 Forecast. A copy of this spreadsheet is available in Appendix B.

Figure 6-3: Peak and Energy Forecasts Based on CED 2017 Forecast

PGE TAC Peak and Energy Forecasts: CED 2017 Forecast, Mid Baseline-Mid AAEE/AAPV

Coincident Peak 1 in 2 (MW)			2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
	ANNUAL MW GROWTH OF DISTRIBUTION SYSTEM															
1	*Line 1 of Mid-Baseline Forecast*	Total End Use Load from Mid-Baseline-Mid AAEE tab	20523	20741	20950	21357	21694	22065	22402	22690	23021	23311	23594	23854	24104	24351
2	*Line 2 of Mid-Baseline Forecast*	System-level EV forecast (will be disaggregated at feeder level)	17	35	60	91	132	163	213	252	298	320	350	389	428	471
3	*Line 9 of Mid-Baseline Forecast*	System-level Other Private Generation (will not be disaggregrated at feeder level)	1057	1115	1125	1133	1140	1147	1153	1158	1162	1166	1169	1173	1176	1181
4	*Line 10 of Mid-Baseline Forecast*	System-level Storage (will not be disaggregated at feeder level)	34	91	143	212	241	270	299	327	355	384	412	440	467	494
5		Transmission-Only Loads	2220	2230	2240	2250	2260	2270	2280	2290	2300	2310	2320	2330	2340	2350
6	*line 1 minus line 2 minus line 3 minus line 4 minus line 5*	Total Modified Distribution System Load	17196	17271	17382	17671	17921	18215	18457	18662	18906	19132	19343	19523	19692	19856
7	*((YearX+1)-(Year X))/Year X*	% growth by year		0.44%	0.65%	1.66%	1.42%	1.64%	1.33%	1.11%	1.31%	1.19%	1.11%	0.93%	0.87%	0.83%
8	*9/1/2017 System Peak Load*	2017 PG&E System Simultaneous Peak Load, obtained from Transmission SCADA, 9/1/2017 @ 17:40	21622													
9	*Line 8 - 2200 MW Transmission-only load*	2017 Distribution System Simultaneous Peak	19422													
10	*% growth times previous year distribution system peak*	Annual Distribution System Simultaneous Peak MW		19507	19633	19958	20241	20574	20847	21078	21354	21609	21848	22051	22242	22427
11	*(YearX+1)-(Year X)*	Annual incremental MW growth of distribution system load at peak		85	126	326	283	332	273	232	275	255	239	203	191	185
12																
13	CUSTOMER CLASS CONTRIBUTION TO INCREMENTAL PEAK LOAD GROWTH (MW) BY YEAR															
14	Residential	40%		34	50	130	113	130	109	93	110	102	96	81	76	74
15	Commercial	12%		10	15	39	34	39	33	28	33	31	29	24	23	22
16	Industrial	33%		28	42	107	93	107	90	76	91	84	79	67	63	61
17	Agricultural	15%		13	19	49	42	49	41	35	41	38	36	30	29	28
18																
19	KNOWN CUSTOMER CLASS PEAK LOAD GROWTH (MW) BY YEAR															
20	Known Commercial Loads (minimum 5 MW assumed known in any year), 2019 and 2020 applications averaged due to timing uncertainty				91	91	14	5	5	5	5	5	5	5	5	5
21	Known Industrial Loads (minimum 40 MW assumed known in any year), 2019 and 2020 applications averaged due to timing uncertainty				90	90	40	40	40	40	40	40	40	40	40	40
22	Known Agricultural Loads (minimum 10 MW assumed known in any year), 2019 and 2020 applications averaged due to timing uncertainty				46	46	10	10	10	10	10	10	10	10	10	10
23																
24	ANNUAL INCREMENTAL GROWTH BY CUSTOMER CLASS THAT SHOULD BE ALLOCATED TO FEEDERS (CORPORATE FORECAST)															
25	*equals Line 14 (known residential adjustments were not applied in LoadSEER)*	Residential			50	130	113	130	109	93	110	102	96	81	76	74
26	*equals Line 15 minus Line 20, 0 if negative*	Commercial			0	0	0	34	28	23	28	26	24	19	18	17
27	*equals Line 16 minus Line 21, 0 if negative*	Industrial			0	17	53	67	50	36	51	44	39	27	23	21
28	*equals Line 17 minus Line 22, 0 if negative*	Agricultural			0	3	32	39	31	25	31	28	26	20	19	18
29																
30		TOTAL ANNUAL INCREMENTAL GROWTH FOR ALL CLASSES			50	151	199	271	218	177	220	200	184	148	136	130
31																

It was confirmed these values were used as part of the disaggregation procedure.

6.1.2 Circuit Level Review

Six individual circuits were randomly selected for evaluation consistent with the graphic shown earlier. An effort was made not to include additional circuits and not just those that may have been discussed during the DPAG meetings.

The resulting drivers for these feeders were 1) capacity needs, 2) exceeding the number of customers subject to an outage on a single circuit or radial underground lateral (PG&E planning criteria), 3) reduce feeder load to less than 600 amps (PG&E Planning criteria) and 4) a feeder with a need mitigated via load transfer. The circuits reviewed were:

- Corcoran 1112 (driver - capacity)
- FMC 1101 (driver - reduce load to less than 600A)
- San Luis Obispo 1108 (driver - load transfer)
- Brentwood 2105 (driver - reduce number of customers subject to an outage to an underground lateral)
- Peabody 2106 (driver- reduce number of customers subject to an outage on to underground lateral)
- Oceano 1106 (driver - reduce the number of customers subject to an outage on the feeder)

Corcoran 1112

The Corcoran 1112 circuit capacity need is mitigated by the Tier 1 Alpaugh New Feeder candidate deferral project. Appendix 6.5: GNA Results-Demand Forecast and Bank/Feeder Capacity Needs of the PG&E 2019 Grid Needs Assessment identified a deficiency for this circuit of 0.51 MW or a 4.37% overload in 2022. To verify this need, the ten-year forecast shape spreadsheet from LoadSEER for the circuit was used to identify the month, day and hour of the forecasted peak for each of the years in the five-year planning horizon (2019-2023). A summary of that data is included the table below. A review of the LoadSEER load forecast shown in the table shows a corresponding deficiency of 509 kW or a 4.36% overload.

Table 6-1: Corcoran 1112 Circuit Need Determination

Corcoran 1112 Circuit Forecast (kW)						
		2019	**2020**	**2021**	**2022**	**2023**
Forecast Type	**Percentile**	**WD-Jun-1900**	**WD-Jun-1900**	**WE-Jul-1900**	**WE-Jul-1900**	**WE-Jul-1900**
Corporate Forecast - CEC Growth	P95	9.080586656	132.0730473	746.7814436	1481.994175	2081.31218
Sum of all Adjustments Forecast	P95	-83.38807754	-166.2740424	-273.637151	-368.754258	-454.90299
Adjustment - DR	P95	-0.05305455	-0.18274345	-0.18274345	-0.18274345	-0.1827434
Adjustment - EE	P95	-83.60090142	-166.2442904	-273.291478	-366.351646	-451.10834
Adjustment - EV	P95	3.80759829	9.04943123	14.29126417	19.53309711	24.7749301
Adjustment - Solar	P95	-3.54171986	-8.89643986	-14.4541939	-21.7529656	-28.386838
Before Project Forecast	P95	12228.2	12268.2	12736.6	13376.7	13889.8
After Project Forecast	P95	11030.8	11070.8	11539.2	12179.3	12692.4
Corcoran 1112 Circuit Capability		11670	11670	11670	11670	11670
Calculation (percent overload)					4.364181662	8.76092545
GNA		0	0	0	4.37	8.74

FMC 1101 Circuit

The FMC 1101 circuit need is driven by the peak load on the feeder which exceeds PG&E's planning criteria to limit feeder load to less than 600 amps for customer reliability purposes. This need is mitigated with the Tier 2 FMC 1102 project which installs a new breaker and feeder (extend circuit is the wording in DDOR) in 2023. Similar to the Corcoran 1112 circuit verification, the ten-year forecast shape spreadsheet from LoadSEER for the FMC 1101 circuit was used to identify the month, day and hour of the forecasted peak for each of the years in the five-year planning horizon (2019-2023). A summary of that data is in the table below. As seen in the summary forecast table below, the 600-amp guideline is exceeded in 2019. There are other similar projects in the GRC to reduce circuit loading to less than 600 amps. This project has been prioritized and scheduled with other similar projects for 2023 to balance financial and human resource requirements.

Table 6-2: FMC 1101 Circuit Need Determination

FMC 1101 Load Forecast (kW)						
		2019	2020	2021	2022	2023
Forecast Type	**Percentile**	**WD-Jul-1400**	**WD-Jul-1400**	**WD-Jul-1400**	**WD-Jul-1400**	**WD-Jul-1400**
Corporate Forecast - CEC Growth	P95	6.14983646	27.4610262	35.6516971	47.2390519	125.10188
Sum of all Adjustments Forecast	P95	-194.351214	-399.952551	-595.36626	-789.24322	-967.85682
Adjustment - DR	P95	-5.75	-22.16	-22.16	-23.39	-23.4
Adjustment - EE	P95	-140.93059	-280.26534	-427.77324	-573.41437	-706.06344
Adjustment - EV	P95	0.79050144	1.89201984	2.97301976	4.38231536	5.64042216
Adjustment - Solar	P95	-48.461125	-99.41923	-148.40604	-196.82116	-244.0338
Before Project Forecast	P95	13619	13434.8	13247.6	13065.4	12964.5
After Project Forecast	P95	13619	13434.8	13247.6	13065.4	12964.5
summer capability (Apr-Oct)	1000	(Amps)				
	21380	(kW)				
Project criteria = loading > 600A	600	(Amps)				
	12830	(kW)				

San Luis Obispo 1108

The San Luis Obispo 1108 circuit capacity need in 2019 was mitigated by load transfers to adjacent circuits. The load forecast for 2020 exceeds the circuit capability by [redacted]. A load transfer of [redacted] is planned to reduce the circuit loading. No work is required for this circuit or the transfer. This was verified by using the ten-year forecast shape spreadsheet from LoadSEER for the circuit to identify the month, day and hour of the forecasted peak for each of the years in the five-year planning horizon (2019-2023). A summary of that data is in the table below. The circuit loading is within limits or capacity once the load transfers are made.

Table 6-3: San Luis Obispo 1108 Need Determination

San Luis Obispo 1108 Load Forecast						
		2019	2020	2021	2022	2023
Forecast Type	**Percentile**	**WD-Oct-1300**	**WD-Sep-1300**	**WD-Sep-1300**	**WD-Sep-1300**	**WD-Sep-1300**
Corporate Forecast - CEC Growth	P95	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Sum of all Adjustments Forecast	P95	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Adjustment - DR	P95	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Adjustment - EE	P95	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Adjustment - EV	P95	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Adjustment - New Commercial	P95	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Adjustment - New Industrial	P95	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Adjustment - Solar	P95	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Before Project Forecast		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
After Project Forecast		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
summer capability (Apr-Oct)	[redacted]	(Amps)				
	[redacted]	(kW)				

Brentwood 2105

The Brentwood 2105 need is driven by the number of customers served on an underground radial lateral subject to an outage with the loss of the source to the lateral. The traditional distribution solution is to construct a back-tie, providing an alternate source to these customers. No load flow is required for this review. A screenshot of the circuit arrangement in **Figure 6-4**: Brentwood 2105 Circuit Arrangement shows the radial system and the 275 customers being served.

Figure 6-4: Brentwood 2105 Circuit Arrangement

This figure has been deleted because PG&E has designated some of the information it contains is confidential per the 15/15 rule.

Peabody 2106

The Peabody 2106 need is driven by the number of customers served on an underground radial lateral subject to an outage with the loss of the source to the lateral. The traditional distribution solution is to construct a back-tie, providing an alternate source to these customers should the circuit lose power. No load flow is required for this review. A screen shot of the circuit arrangement below shows the radial system and the 650 customers being served.

Figure 6-5: Peabody 2106 Circuit Arrangement

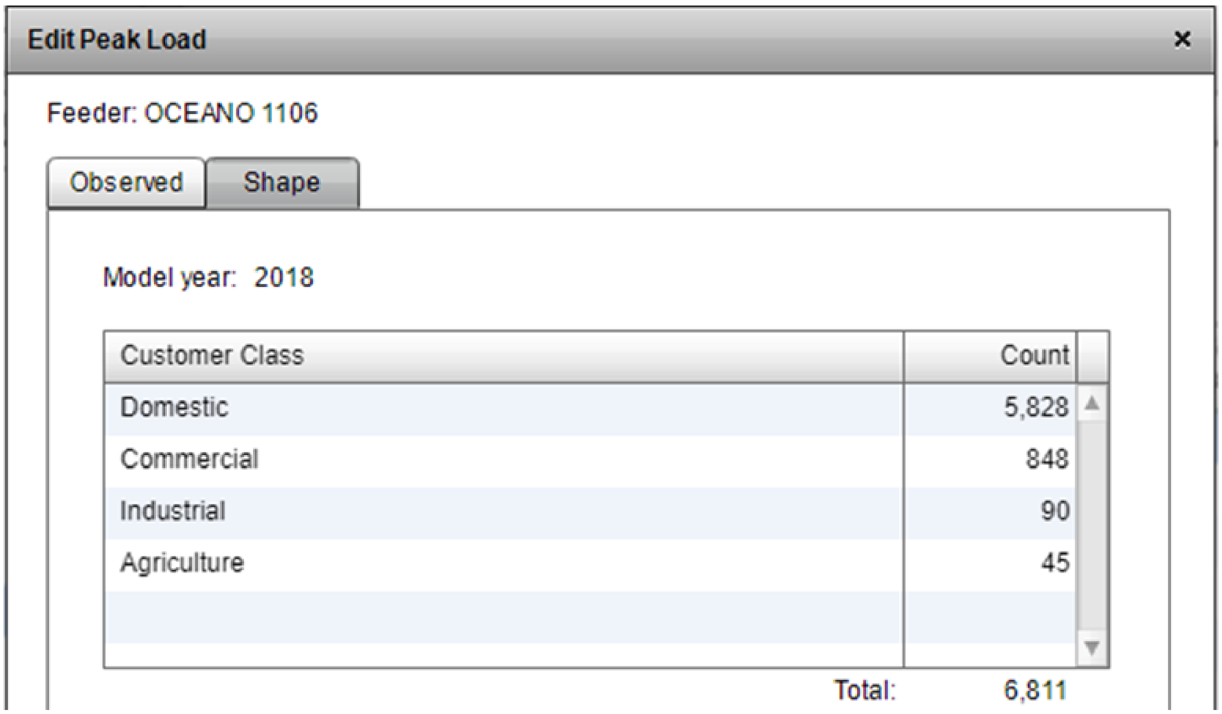
This figure has been deleted because PG&E has designated some of the information it contains is confidential per the 15/15 rule.

Oceano 1106

The Ocean 1106 need is driven by the need to reduce the number of customers on a circuit subject to an outage with the loss of the circuit. PG&E's objective is to reduce the number of customers subject to an outage with the loss of the circuit to less than 6000. The traditional distribution solution is to construct a back-tie, providing an alternate source to customers should the circuit lose power. No load flow is required for this review. A screenshot in **Figure 6-6**: LoadSEER Table Summarizing Customer Count in Oceano 1106 below summarizes the number of customers being served by the Oceano 1106 circuit, in this case 6811 customers.

Figure 6-6: LoadSEER Table Summarizing Customer Count in Oceano 1106

Oceano 1106 - LoadSEER



Customer Class	Count
Domestic	5,828
Commercial	848
Industrial	90
Agriculture	45
Total:	6,811

Results

In each of these circuit reviews the loading and percentage overloads identified from LoadSEER matched the GNA and the customer counts were identified and consistent with the PG&E policy and planning criteria.

6.2 Development of DER Operational Requirements

Approach

The approach taken was to “walk through” the process used by PG&E to develop the operational requirements for Tier 1 Day Ahead projects and compare them to the data presented in the GNA/DDOR. This same information was also presented at the DPAG meeting. The requirements included months needed, number of calls per year, estimated hours of need, overcapacity (%) and maximum duration per call.

Results

The DER operational requirements for Alpaugh New Feeder and Santa Nella Bank and New Feeder projects were reviewed as described below.

Alpaugh New Feeder

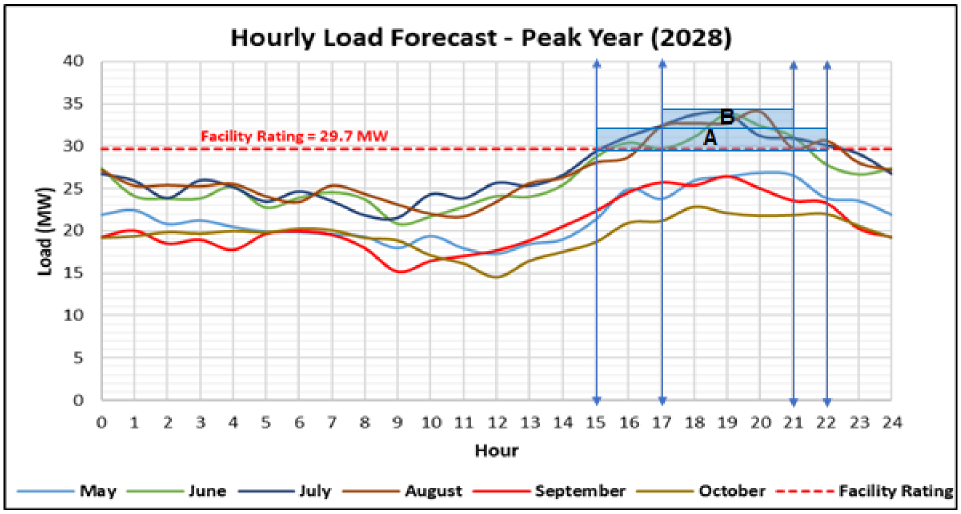
The DER requirements were obtained from LoadSEER information. Peak hourly load forecasts for years following the in-service date through the end of the planning horizon are plotted for each summer month and compared against the facility rating. The background data for this plot comes from the LoadSEER forecasts report. This is the same data used previously to obtain potential facility overloads. For this project, two needs are being mitigated – Corcoran Bank 3 overload and Corcoran 1112 overload. The combined requirements of each need are considered when determining the project requirements. The required load, months and hours can be obtained directly from the plots. There is a slight overload in 2021 with a larger overload in 2022 and beyond. The overload is slight and could easily be a result of forecast uncertainty. Since it will be difficult to obtain a DER or traditional solution in 2021 and the load is small and uncertain, PG&E has established the in-service date as 2022. If the slight overload occurs, they will attempt to identify a temporary work around or accept the overload condition for 2021.

Figure 6-7: LoadSEER Annual Corcoran Bank 3 Forecast

Requirement	Offer Size (MW)	Term (Years)
A	3	2021-2028
B	1.5	2023-2028

Figure 6-8: LoadSEER Hourly Corcoran Bank 3 Forecast (2028)

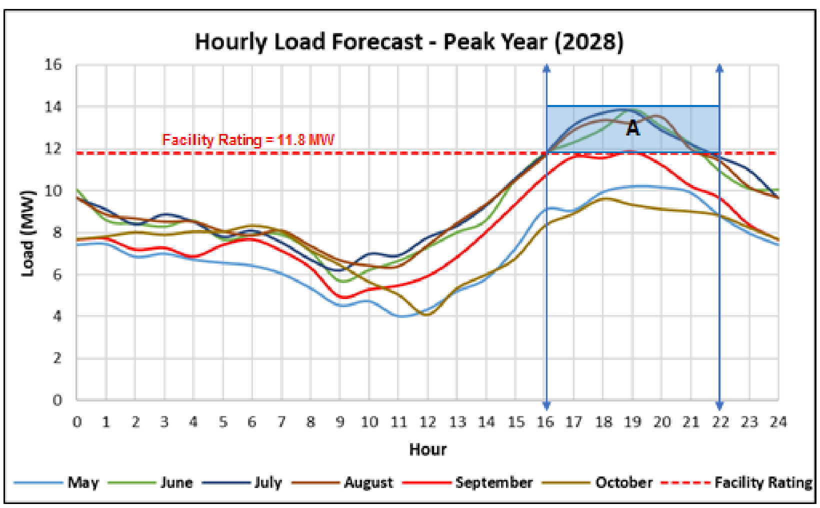
Need: Corcoran Bank 3



Requirement	Offer Size (MW)	Delivery Months	Delivery Hours	Hours Duration
A	3	Jun-Aug	3:00PM-10:00PM	7
B	1.5	Jun-Aug	5:00PM-9:00PM	4

Figure 6-9: LoadSEER Corcoran 1112 Circuit Forecast (2028)

Corcoran 1112



Requirement	Offer Size (MW)	Delivery Months	Delivery Hours	Hours Duration
A	2.5	Jun-Sep	4:00PM-10:00PM	6

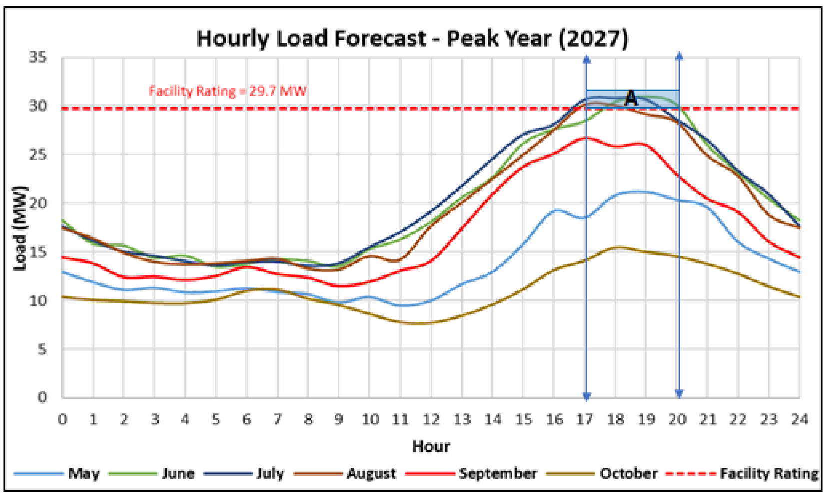
Santa Nella Bank and New Feeder

Similar to the Alpaugh New Feeder project, this Santa Nella Bank and New Feeder project mitigates multiple needs – overloads on Canal Bank 1, Canal Bank 2, Ortiga Bank 1, Canal 1103 circuit, and Ortiga 1106 circuit. This project also mitigates a slight overload on the Santa Nella 1104, but this need is not being solicited as part of this opportunity because the need is very small.

The same methodology for identifying requirements is used. Plots from LoadSEER are used to identify loading requirements, needs dates and duration of the need.

Figure 6-10: LoadSEER Hourly Canal Bank 1 Forecast (2027)

Canal Bank 1

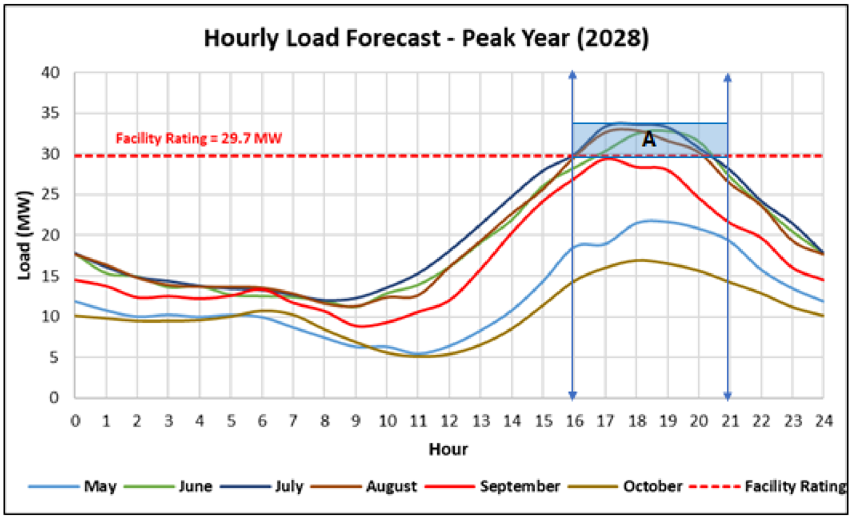


Requirement	Offer Size (MW)	Delivery Months	Delivery Hours	Hours Duration
A	1.5	Jun-Aug	5:00PM-8:00PM	3

Note the peak load for the Canal Bank 1 is in 2027. The load does decrease slightly in 2028 because DER, EE and EV growth exceeds the bank growth.

Figure 6-11: LoadSEER Hourly Canal Bank 3 Forecast (2028)

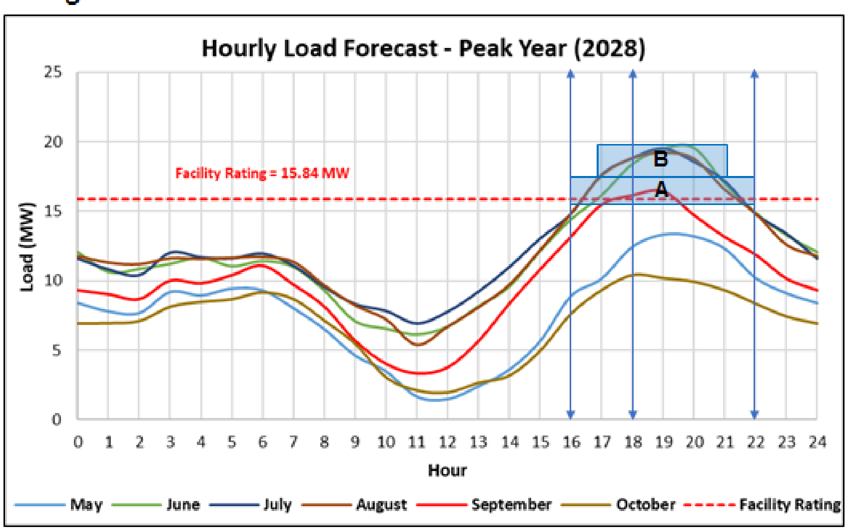
: Canal Bank 2



Requirement	Offer Size (MW)	Delivery Months	Delivery Hours	Hours Duration
A	4	Jun-Sep	4:00PM-9:00PM	5

Figure 6-12: LoadSEER Hourly Ortiga Bank 1 Forecast (2028)

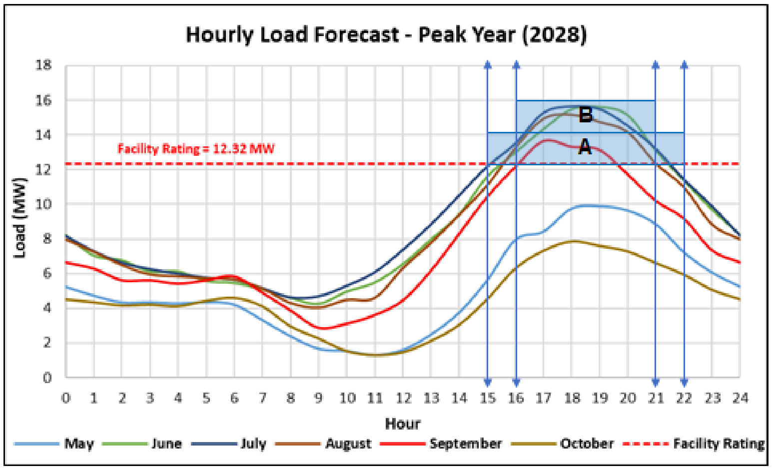
: Ortiga Bank 1



Requirement	Offer Size (MW)	Delivery Months	Delivery Hours	Hours Duration
A	3	Jun-Sep	3:00PM-10:00PM	7
B	1	Jun-Sep	4:00PM-9:00PM	5

Figure 6-13: LoadSEER Canal 1103 Circuit Forecast (2028)

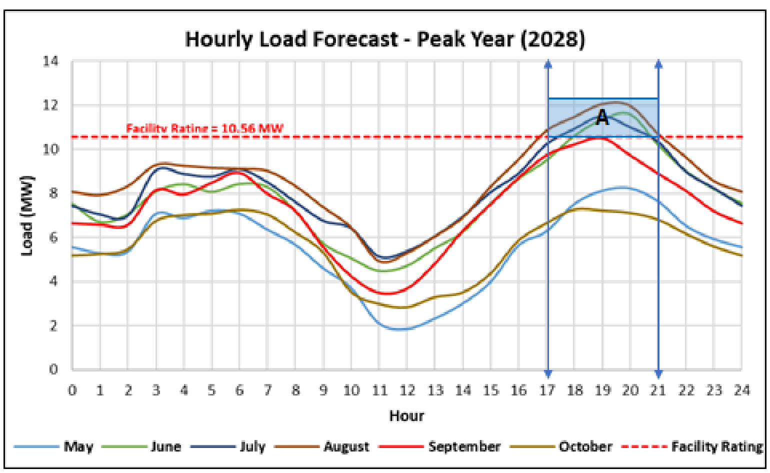
Canal 1103



Requirement	Offer Size (MW)	Delivery Months	Delivery Hours	Hours Duration
A	2	Jun-Sep	3:00PM-10:00PM	7
B	1.5	Jun-Sep	4:00PM-9:00PM	5

Figure 6-14: LoadSEER Ortiga 110 Circuit Forecast (2028)

Ortiga 1106



Requirement	Offer Size (MW)	Delivery Months	Delivery Hours	Hours Duration
A	1.5	Jun-Sep	5:00PM-9:00PM	4

6.3 Development of Capital Costs

Approach

The approach used to verify the capital costs included requesting data from PG&E to support selected projects in their GNA/DDOR and reviewing that data to determine how it was developed and if it is reasonable.

Background

PG&E develops the capital cost of traditional wires solutions as follows:
Generally, unit costs are calculated by averaging recorded total expenditures of similar jobs, or specific components of jobs, from recently completed work. These unit costs are used as a preliminary budgeting tool to assist in forecasting project costs based on a high-level scope of work during the initial phases of a job. As projects move through the course of design and engineering, project costs are refined to better reflect the more detailed scope of work. Completion of the design and engineering stage of a project results in a job "estimate" specific to the identified scope of work for a given project.

This is consistent with industry practice. According to the American Association of Cost Engineers[6] (AACE) cost estimating classification system, initial cost estimate accuracy would fall into the Class Five (-50% to +100%) or Class Four (-15% to +50%) range. Thus, for projects that are in the early stages of development the overall accuracy of the estimate is expected to be about -30% to + 70% of the final cost estimate/actual costs of the project.

The unit cost data used for these projects are available in PG&E's 2020 General Rate Case Exhibit (PG&E-4), Chapter 13, WP 13-45. Note the forecast documented in the GRC includes escalation but the unit costs in AL 5435-E do not.

We reviewed the costs in two ways. First, PG&E uses the costs from the GRC for these candidate projects. We reviewed seven projects and verified the costs for four of them which have 2022 in-service dates. The in-service dates for two of the other projects were beyond the 2022 and therefore the entire costs of these projects were not in the latest GRC. The final project, Santa Nella New Bank and Feeder, had progressed in its development and the scope had changed since the costs were developed. Therefore, the estimated costs had also changed, and we were unable to replicate them (unknown scope description at time of specific time of cost development).

For the second review, we received the scopes for the same seven candidate projects and developed costs using the unit costs from the GRC. The results ranged from +/- <1% to 14%, except for the Santa Nella project that was further along in its development.

[6] Link to AACE Cost Estimate standard practice regarding cost estimates. http://www.emnrd.state.nm.us/MMD/MARP/permits/documents/MK006RE_20100917_St_Anthony_Closure_Cost_Estimate_Attachment3.pdf

The DDOR costs greatly exceed our estimated costs with the provided defined scope for this project, which is not surprising

Results

The costs within DDOR could not be duplicated exactly using the GRC Unit cost approach. While the general process is to use the GRC unit costs, it is reasonable to expect local engineers to adjust costs based on local conditions, for example trenching in areas with known contamination resulting in higher trenching costs. We were able to confirm the GRC costs were used for projects with in-service dates of 2022 or earlier. Except for the costs for the Santa Nella project, we were also able to approximate, but not duplicate, the DDOR costs using the project scope and the GRC unit costs. For those project costs we could not duplicate because of the adjustments made by engineering, we believe based upon the amount of adjustment that the values are consistent with the Unit values and overall are reasonable. Unit costs can vary for various reasons such as, but not limited to, labor rates, local conditions, and material cost arrangements with manufacturers. Based on our experience the unit costs used for this work are reasonable

6.4 Development and Use of LNBA Values

The Locational Net Benefits Analysis (LNBA) value is the net present value (NPV) of the annual costs associated with deferring a planned project. The annual cost of deferral is the revenue requirement associated with the planned project which includes annualized capital and operations and maintenance (O&M) costs. The LNBA value can be expressed in a number of ways – as an absolute value ($), as an annualized number ($/yr.) or as part of a metrics ($/kW-year). The latter value expressed as a $/KW-Yr. value is determined by dividing the NPV of the deferral costs by the product of two values – the number of years of deferral and the maximum amount (KW) of need during the deferral period. The LNBA value is used as an indicator as an indication of the economic feasibility of a non-wire solution. A non-wire solution project with a higher value of LNBA would indicate, in general, that it is a more economically feasible than a project with a lower value. PG&E published the actual LNBA values in its DDOR report. . These actual LNBA values are used in the calculation of prioritization metrics.

Methodology

We reviewed the methodology PG&E used to develop the LNBA values included in its DDOR Report. A summary of that review follows.

Deferral Timeframe

Deferral period is a key input to the LNBA calculation. The deferral period used by PG&E is a varying six- to seven-year period (2023-2028, 2022-2028) for candidate deferral projects depending upon the projects' start date.

LNBA Calculation

The deferral value associated with the deferral of a planned project is the NPV of all the annual deferral values during the deferral timeframe. For example, the 5-year deferral value is the sum of the Net Present Values (NPV) of the 1-year deferral value of the proposed solution for the first five years. The 1-year deferral value of the proposed solution is the sum of the 1-year deferral value of the equipment capital cost and the operations and maintenance (O&M costs) associated with the new equipment that would have been added if the traditional project had been built.

The 1-year deferral value associated with equipment is calculated by multiplying the revenue requirement for the project with the RECC factor.

*1-Year deferral value = Project Revenue Requirement * RECC,*

Where RECC is defined by the following equation:

$$\text{RECC} = \frac{(r-i)}{(1+r)} \left(\frac{(1+r)^N}{(1+r)^N-(1+i)^N} \right)$$

Where, i = assumed inflation over the period of interest, r = assumed discount rate and N = is the assumed life of the traditional project.

The Project Revenue Requirement is calculated by multiplying the estimated capital cost of the equipment with the Revenue Requirement Multiplier (RRQ Multiplier or RRM). The RRQ Multiplier represents costs recovered from utility customers and includes costs such as taxes, franchise fees, utility authorized rate of return, and overheads. In equation form, the Project Revenue Requirement is:

*Project Revenue Requirement = Estimated Project Capital Cost * RRQ Multiplier*

If a DER is procured instead of building a traditional wires project, utility customers also benefit by avoiding any annual O&M activities associated with the traditional wires project equipment which is not built. Since O&M is an expense item that is passed to customers in the year it is incurred, it is not multiplied by the RECC factor or the RRM. Since O&M costs are incurred in the year they are performed O&M is also subject to inflation adjustments.

The complete expression of the cost reduction associated with a one-year deferral is thus:

Deferral Benefit = [[Project Capital Cost] x [RECC Factor] x [RRQ Multiplier] + annual O&M]

To calculate the value of a multiple-year deferral, the yearly deferral values for each year after the first year are calculated and simply discounted to a present value using a discount factor derived from same discount and inflation rates used in the RECC factor and then the discounted values are summed together to form the multiple year deferral value.

The key assumptions for the LNBA calculation include the following:

- **Discount Rate**: Derived from the utility's weighted average cost of capital;
- **Inflation Rate**: Inflation rates for equipment and O&M as assumed as per utility's practice;
- **Life of a Traditional Project**: Assumptions for project life as per utility's practice;
- **Equipment Capital Cost**: Cost of the project equipment as per utility's practice; and
- **O&M Costs**: Cost of O&M as per utility's practice. Expressed as a percentage of the project's capital cost.

PG&E used a simplified LNBA calculator which uses calculations similar to those in the E3 LNBA tool. However, PG&E used their own set of assumptions for the key inputs to the deferral calculation. The inputs and outputs of PG&E's LNBA calculation are discussed below.

Verification of LNBA Results

We verified the inputs that went into the LNBA calculation, as well as the calculation itself, as discussed below.

Key inputs

The key inputs to the LNBA calculation are shown in **Table 6-4**: Key LNBA Calculation Inputs below. PG&E used a discount rate of 7% which is PG&E's after-tax weighted average cost of capital and reflects CPUC authorized cost of equity, cost of debt, and capital structure, as well as current tax rates. One other key input for the LNBA calculation is the capital cost of equipment for each project.

Table 6-4: Key LNBA Calculation Inputs

Input	General	Substation Bank	Primary Feeder	Poles and towers	Source
Revenue Requirement Multiplier	1.34	1.34	1.38	1.40	PG&E assumption
Equipment Inflation	2.5%	2.5%	2.5%	2.5%	Standard assumption in LNBA Calculator
O&M Inflation	2.5%	2.5%	2.5%	2.5%	Standard assumption in LNBA Calculator
O&M Factor	5.5%	2.5%	7.5%	7.0%	PG&E assumption
Book Life	46	46	46	44	PG&E assumption
RECC	0.049	0.049	0.049	0.050	Calculated
Discount rate net or project inflation (5/yr)	4.4%	4.4%	4.4%	4.4%	Calculated

Results

The LNBA values shown in PG&E's DDOR report were verified using the formula shown in E3's LNBA calculator for one of the planned projects (Project ID: 74001699, GNA Facility Name: Canal Bank 1) as shown in **Table 6-5**: Canal Bank 1 LNBA Verification. The calculated values (LNBA range) match those provided in the DDOR report for this circuit. In this table, the values from PG&E's LNBA calculation are shown in column 2. The corresponding values calculated using E3's formula, as well as the formula themselves are shown in the 3rd and 4th columns respectively.

Table 6-5: Canal Bank 1 LNBA Verification

LNBA Item	Values shown in DDOR Report	IPE Calculations based on E3 LNBA formula	E3 LNBA formula
Project ID / Name	74001699	74001699	Input
GNA Facility Name	CANAL BANK 1	CANAL BANK 1	Input
Planned Investment Type	Bank	Bank	Input
Project Cost ($k)	7256.00	7256.00	Input
Revenue Requirement Multiplier	1.34	1.34	Input
Discount Rate (%/yr.)	0.07	0.07	Input
Equipment Inflation	0.03	0.03	Input
O&M Inflation	0.03	0.03	Input
O&M Factor	0.03	0.03	Input
Book Life	46.00	46.00	Input
DER Install Year	2022.00	2022.00	Input
Cost year basis	2019.00	2019.00	Input
Analysis Year	2019.00	2019.00	Input
Deferral Years	7.00	7.00	Input
Number of no deficiency years after the DER Install yr.	0.00	0.00	Input
Incremental O&M Cost	182.85	182.85	C4*C9
RECC	0.05	0.05	(C6-C7)/(1+C6)*(1+C6)^C10/((1+C6)^C10-(1+C7)^C10)
Discount rate net or project inflation (5/yr.)	0.04	0.04	(1+C6)/(1+C7)-1
RR Instal Yr. $'s	10478.37	10478.37	C4*C5*(1+C7)^(C11-C12)
RR * RECC	511.56	511.56	C19*C17
Capital Benefit in Install Year	3159.50	3159.50	PV(C18,C14,-C20,0,1)
O&M Deferral Benefit in Install Year	1216.16	1216.16	PV(C18,C14,-C16,0,1)*(1+C8)^(C11-C12)/(1+C18)^B15
Value of Deferral Benefits ($000s) in Install Year	4375.66	4375.66	C21+C22

LNBA Item	Values shown in DDOR Report	IPE Calculations based on E3 LNBA formula	E3 LNBA formula
Value of Deferral Benefit ($000s) in 2019	3571.84	3571.84	C23/(1+C6)^(C11-C12)
Max Need (MW/Vpu/MVAR)*	9.28	9.28	Verified
Normalized Deferral Benefit ($000s/MW-yr.)	54.99	54.99	C24/C25/C14

**for all circuits belonging to this project*

LNBA Inputs and Outputs

As part of our review we confirmed the input costs to the LNBA calculator and associated output LNBA values (i.e. $/kW-yr.) are consistent with the DDOR. Note this review was prior to PG&E's latest changes for Days/Year and Hours/Call for Tier 2 projects. The results of this latest revision were not verified.

6.5 Screening of Projects

Approach

The approach to verifying the screening of projects was to review how projects are identified, review screens of the GNA/DDOR projects for timing and type of service and compare it to the results included in the GNA/DDOR report and spreadsheets.

Projects identified are generated from Chapter 13 of the 2020 PG&E GRC plus new projects that have been created and entered into LoadSEER, to mitigate newly identified overload conditions. and reduce number of customers subject to outages as described by PG&E planning guidelines. This results in a list of all capacity related projects which pass the technical screening and are potential DDOR opportunities. So, no additional technical screening is required. Recently completed projects are also maintained on this list as a historic record. This list is broken down by Distribution Planning Area (DPA) for local review of exceptions, such as work currently underway or completed. This list is used as for input of capacity projects into GNA. **Table 6-6**: Capacity Project List for Canal DPA is a sample sheet from of a small DPA.

Table 6-6: Capacity Project List for Canal DPA

Division	DPA	Project Type	Due Date	Exclude	Project Cost	Major Work Category	
Yosemite	Canal	Replace existing bank	5/1/2022	Yes	$5,100,000	46 & 06	GNA MWC 46 - Replace Santa Nella Bank #1 and install 1-/12 kV feeder
Yosemite	Canal	Replace existing bank	5/31/2014	No	$0	54	Replace Ortiga Bk 2 - SAS

The needs generated by PG&E Guidelines regarding maximum load on a feeder (600A) and number of customers subject to an outage are also identified from LoadSEER. They are reviewed to confirm they meet the technical requirements. The timing for these types of projects is discretionary and PG&E is attempting to complete one or two a year.

The power flow and voltage analysis simulation tool, CYMDIST is used to identify line segment overload or low voltage conditions. Each line segment overload or low voltage mitigation solution is entered into GNA. However, the time requirements for these needs are short and are filtered out as part of the timing screen process.

Results

The technical screening for substation and circuit capacity requirements is completed by planning engineers reviewing the DPA lists mentioned above. Projects that meet the technical and timing requirements are considered as potential DDOR candidates. All capacity projects in Chapter 13 of the GRC and newly identified capacity related work in LoadSEER can be met by one the four DER resources services. The projects to reduce the circuit loading to less than 600 amps and to reduce the number of customers on a circuit or lateral are also listed. The in-service dates for these projects are normally discretionary. In addition, voltage and overload issues identified by CYMDIST can also be mitigated by DER services and are included in the GNA but do not normally pass the timing screen.

The in-service date for capacity work is identified in LoadSEER. Those projects inside the 2022 window are screened out. Line section overload and low voltage projects from CYMDIST are normally required in the near time and are filtered out as part of the timing screen.

An independent review of the projects in Tiers 1-4 met the screening requirements. A review of projects not in the Tiers 1-4 did not identify any that should have been included as candidate deferral projects.

6.6 Prioritization Metrics and Process

Approach

The approach used was to review the metric prioritization process with PG&E staff and independently review metric components and how they were used to develop the overall three prioritization metrics. Then the Tier 1-3 projects were prioritized to determine if the methodology described in the GNA/DDOR and DPAG meetings was the methodology used to develop the final prioritizations of candidate deferral projects in Tiers 1-3.

Note discussion of the prioritization metrics and methodology are included earlier in this report.

Results

Parts of the methodology used prioritize candidate opportunities are unclear and the results are not easily replicated without explanation. Most of the metric components have numerical values but PG&E evaluates the components (and the prioritization metrics themselves) qualitatively.

There are no predefined levels or limits between the subjective rankings. In most cases it appears the values for the components tend to naturally fall into “clumps” and these natural clumps or groups are used for the relatively high, moderate and low rankings. We believe this “clumping” is a result of this particular set of candidate opportunities and another set of candidates with different costs and requirements would not necessarily result in “clumps” or groups that can be used to establish relative rankings. In that case predefined levels or values would be required for prioritization.

One of the components for the Market Assessment, Days/Year, is evaluated differently for Real Time and Day Ahead candidates.

That is not apparent without discussion with PG&E. If there are separate evaluation criteria, for Real Time and Day Ahead candidates, they should be in separate component columns to make it clearer to the reader. The Number of Grid Needs component of the Market Assessment could also be unclear. For three candidates, Alpaugh New Feeder, Santa Nella New Bank and Feeder and Dairyland 1110, the number of grid needs shown in DDOR Appendix C, Basis for Prioritization Metrics, differs from the number of needs shown in DDOR Appendix A, Planned Investments. The explanation for this difference is that mitigated of one of the needs also mitigates another need. As a result, only one mitigated need is counted. This is not clear and should be reconsidered to show all the needs are mitigated.

Summary

The prioritization process which is subjective cannot be easily replicated without additional information. The prioritization metrics for the DDOR candidates in DDOR, Table 12, Preliminary Prioritization Metrics and Rankings of Candidate Deferral Opportunities, is a qualitative assessment of the individual comments for each metric as shown is DDOR Appendix C, Basis for Prioritization Metrics.   As mentioned earlier, generally speaking the worst individual ranking was used for the overall ranking. The purpose for this approach is not to predict which candidate would be the most successful but to highlight potential red flags for candidate projects. During our review, the prioritization of Forecast Certainty for the Alpaugh New Feeder was changed from a relatively moderate ranking to a relatively high ranking which makes this a stronger candidate for Tier 1.

7 Discussion of Other Items

7.1 Miscellaneous – Observations, Conclusions and Recommendations

IPE Report

- We observe the May Ruling established a broadened scope for the IPE, along with a more detailed reporting requirement and provided substantially less time to complete the new scope. This is the major reason for the revision in the timing of the IPE report production and ED and IOU review cycle.

- In general, we observe that the new V&V role of the IPE requires substantial time to develop a workable/practical approach and to work through the many complex software systems and proprietary software packages to accomplish the needed V&V. For example, even though the IPE started the design of the V&V for the System Level review prior to the GNA/DDOR filings, the actual implementation was ongoing into mid-October. We recommend that if the CPUC wants to continue that role, a future ruling be established providing requirements for the IOUs to prepare showings that would allow the IPE to perform its V&V more efficiently and in the allotted time.

Forecast and Disaggregation Review

- We observe the critical importance of the load and DER forecasting, load and DER disaggregation and the application of local known loads as critical to the DIDF process. For this reason, we recommend that the IOUs include in the GNA/DDOR report a comparison of the net load forecasts in the previous GNA/DDOR with the actual weather adjusted net load for each circuit. We are aware that some IOUs perform such a check already. We are recommending that it be documented in the GNA/DDOR report. We believe this will be valuable to many stakeholders including the CEC.

LNBA Calculation Period

- Currently all IOUs calculate the LNBA values for candidate deferral projects using the same period as defined in the May Ruling. They do not use the same period for the calculation of the values (ranges) in the GNA. We recommend that they all use the same period and recommend that it be the same as that defined in the May Ruling.

Traditional Project Costs

- The development of traditional project costs for DDOR varies by utility and are difficult to replicate. It is possible to approximate the costs and determine if the costs are reasonable but not as easy to duplicate them.

If duplicating traditional project costs are important to the V&V function, the utilities should be required to provide that information. If confirming the costs appear reasonable, as in the case for PG&E, the existing pricing information is sufficient.

LNBA Calculation Assumptions

- 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.

Back-tie Planning and Analysis

- We observe that all three IOUs have proposed projects that have included back-tie benefits/needs. We also observe that these back-ties are often included in projects that also provide capacity service. These back-ties functions have been proposed to improve reliability and/or resiliency. We also observe that consideration of back-ties is becoming more important to the discussion of projects in the DIDF.

  We understand that the IOU's distribution planning emphasizes meeting customer demand reliably under normal (N-0) condition and also considers back-ties; it is our understanding that back-ties are primarily used to address customer reliability under non-normal system conditions (N-1, N-2, etc.). As such we believe that planning for back-ties ultimately ends up being a determination of which non-normal conditions are going to be addressed with investments. In view of the increase in the number of projects with back-tie components or benefits we recommend that the IOUs document 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.

Segment Level Reporting

We observe that this is the first year that the IOUs are required to report segment level information. We also observe that the three utilities took different approaches – including proving a list of all segments in the GNA whether they had a need or not to just listing the segments with needs. We also observe that because the segment analysis was limited to the first three years of the GNA planning period that any segment needs were screened out as a result of the application of the Timing Screen. Thus based upon the current framework, segment level needs do not result in candidate deferral projects.

For some utilities, we observe that they have a large number of segments and as a result they may have a large number of segment capacity or voltage support needs. The reporting of these dominates the GNA reports in terms of volume.

We suggest the CPUC provide additional guidance on how these line section results and needs should be addressed in the GNA/DDOR reports (i.e. report all segments, only those with needs or some other approach). We conclude it is reasonable to expect the utilities to do this review and analysis at the circuit segment level as part of the GNA process. The question is whether it is necessary to require all of this information to be included in the GNA report itself. One option is to require the utilities to describe how the line segment needs were determined and summarize the results of the line segment assessment.

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Appendix A DPAG Survey and Comment Responses

PG&E sent a questionnaire to the DPAG members to solicit feedback from the DPAG and also solicited comments by email. The feedback sought was to PG&E and/or the IPE per the CPUC May 7 Ruling. There were a number of responses as documented here in this appendix.

A.1 Comments and Questions Directed to IPE

Energy Division Questions to IPE

Question Number 18

Category 2018&2019 GNA/DDOR, Defining the Grid Needs

Question Direct to: IPE

Question: For each IOU please offer your analysis of whether you agree with the ranking criteria of which DDOR projects will be included in an RFO. Please comment if you think any projects should be added or subtracted from the Tier 1 category.

Response: The review of the ranking criteria is included in Section 4.2 and our recommendations with respect to projects in Tier 1 are in Section 5.

Public Advocates Office Comments

Letter Attached and responses included throughout the body of the report.

A.2 Comments and Questions Directed to PG&E

Survey Questions and Responses

Dimension Renewable Energy
What feedback do you have regarding the candidate projects that PG&E proposed for solicitation? PG&E has selected reasonable projects to put out to bid. Some of the tier 2 back-tie projects are likely unfinanceable as structured (real time calls for 24 hours and often any time of the year) as they would require a lot of capacity with limited ability to earn revenue in wholesale markets. However, if 1)the length of the call could be more precise based on actual response times; 2) the months were narrowed to those where outages are prevalent; and 3) the needed capacity was sized on a more granular 8760/570/etc. basis*, projects may be more feasible. It would also be important to know what penalties there would be for non-performance.

(* e.g., for a 1MW need based on the peak loading in that area, most hours the need may only be 200kW, allowing for part of the battery to be available to participate in markets and still be available to respond to likely loads at any hour).
What feedback do you have regarding the candidate projects that PG&E did not propose for solicitation? Per the discussion, it would be interesting to see if the Estrella project could be separated into distinct projects, as some of the distribution capacity projects, in particular, may be more manageable on their own for solicitation and lower the overall cost of the combined project.
What feedback (if any) do you have on PG&E's DPAG meeting(s) to date? We appreciate all the work that PG&E put into identifying these projects and running an informative and productive meeting.
What additional information do you need, if any, to determine feasibility of bidding on a project in the 2019 DIDF RFO cycle? Please refer to the comments above
What questions or comments do you have for the Independent Professional Engineer regarding his presentation and review of PGE's GNA/DDOR and candidate deferral prioritization process? Per the discussion at the meeting, it would be useful to have some validation of the unit costs that go into determining the LNBA in addition to validation of the LNBA calculation.
Any additional questions or comments for PG&E? We do not have additional comments at this time. Thank you for the opportunity to participate in the DPAG meeting.

CESA
What feedback do you have regarding the candidate projects that PG&E proposed for solicitation? CESA supports PG&E's recommendation to move forward with three Tier 1 projects, as these three projects (Alpaugh New Feeder, Calfax Bank 2, Santa Nella New Bank/Feeder) seek distribution capacity dispatched on a day-ahead basis, which has proven to be a well-suited application for DERs. The LNBA values are moderate, but these projects strike the right balance of being achievable for deferral. Given the three-year-ahead timeframe, it is worthwhile to move these projects to an RFO. The Alpaugh New Feeder, Calfax Bank 2, and some downstream needs of the Santa Nella New Bank/Feeder projects were identified as having longer-duration overloads of 7 to 16 hours. Certainly, there are long-duration storage technologies that should be able to compete to deliver on these long-duration needs, but, as PG&E has done in the past, CESA recommends that PG&E continue to create partial delivery windows such that a portfolio of shorter-duration DERs to meet the full need. In doing so, PG&E will invite greater market participation in the RFO.
What feedback do you have regarding the candidate projects that PG&E did not propose for solicitation? CESA has no additional feedback on the candidate projects at this time. Pending additional information on back-tie service requirements (as detailed in our response to Question 5), CESA tentatively supports PG&E's proposed tiering of projects. However, if the 24-hour service requirement is not substantiated for the Tier 2 and 3 projects, particularly for the Camp Evers 2107 and FMC 1102 projects, CESA believes that these projects could be considered for Tier 1 status. Even with the real-time requirements, the Camp Evers 2107 and FMC 1102 projects have such low overcapacity percentages (3%-4%) that DERs such as energy storage could feasibly reserve capacity for this back-tie requirement while using the rest of its capacity for other services. Pursuant to the Multiple-Use Application (MUA) rules, such capacity-differentiated services represent a smart and possibly cost-effective means to deploy and operate energy storage to deliver great ratepayer value. Furthermore, these two projects generally rate favorably across the other prioritization metrics, especially around LNBA value and number of customers driving the need – the latter of which demonstrates a large opportunity for BTM resource deployment as well as stronger forecast certainty. CESA also supports the continued monitoring of the Estrella Substation project, which represents a high-dollar and high overload project. CESA understands that this substation is intended to provide both distribution capacity and reliability back-tie services. Given the potential for lower-cost DER alternatives, PG&E should provide more detail on whether and how these service requirements could be decoupled.

What feedback (if any) do you have on PG&E's DPAG meeting(s) to date? CESA appreciates the well-run and informative DPAG meeting that PG&E and the IPE have prepared. For this cycle, CESA recommends that the DPAG stakeholders aim to seek informal consensus through these meetings to minimize the need to submit protests to PG&E's advice letter filing on November 15, 2019. While consensus may not always be achieved, CESA hopes that stakeholders can work together in these DPAG meetings to come to a general agreement on the candidate deferral projects to be submitted for an RFO in order to minimize regulatory approval delay. Last year, the launch of the DIDF RFO was delayed due to staff review needed because of stakeholder protests, but if possible and ideally, the IOUs, IPE, and stakeholders would achieve this consensus to ensure a timely launch of the RFO in January, at the latest.
What additional information do you need, if any, to determine feasibility of bidding on a project in the 2019 DIDF RFO cycle? CESA has no requests for additional information at this time. CESA appreciates the load curves and equipment rating limits provided for each circuit/feeder, as done at the DPAG meeting. Similarly, as done for the Calfax Bank 2 project, CESA appreciates PG&E providing any charging constrained locations for the candidate projects. Any information on charging constraints is helpful, if there are any for other project locations.
What questions or comments do you have for the Independent Professional Engineer regarding his presentation and review of PGE's GNA/DDOR and candidate deferral prioritization process? CESA seeks to understand the reliability (back-tie) service requirements, which PG&E defined as requiring 24 hours of fast reconnection and availability of excess reserves under an n-1 contingency scenario. However, CESA is unclear on whether back-tie service must be subject to a 24-hour requirement. While CESA understands that five-minute real-time dispatch is needed given the unplanned nature of outages from distribution infrastructure elements, it is not clear why such back-tie must be provided across a 24-hour basis. CESA requests that PG&E provide additional information on the average or other trend data on the duration of these outage and fault conditions, which necessitate back-tie services (e.g., via back-tie switches), and that the IPE seek and validate this additional information. This information is not provided in either their GNA or DDOR filings and was discussed to some degree at the September 19, 2019 DPAG meeting. As PG&E noted, baseload needs are not suitable for deferral by DERs, so substantiating this service requirement will be important to understand whether DERs can provide back-tie services at all, or only in certain circumstances where back-tie is only required on a more time-limited basis. Ultimately, CESA seeks to understand whether it is appropriate to set a blanket 24-hour requirement for back-tie services, or whether a project-specific assessment on the duration of back-tie service should be established. Furthermore, CESA seeks to better understand why certain candidate deferrals required islanding in addition to real-time back-tie service. This information was not provided in the GNA or DDOR filings and was inadequately covered in the DPAG meetings. CESA also

requests further information on how islanding capabilities would be established as service requirements for DERs. Lastly, questions were raised on whether the Estrella Substation could have its capacity and reliability back-tie service needs decoupled such that DERs could more feasibly address the distribution capacity need. Since the in-service date of this project is not until 2024, it may be worthwhile to dedicate some time in the upcoming DPAG meetings to discuss this high-cost project in order to exhaust potential DER alternative options.
Any additional questions or comments for PG&E? For future DPAG meetings, though it does not have to be this 2019 DIDF cycle, CESA would like to explore with PG&E, IPE, and the Commission on whether resiliency (microgrid) needs are best addressed through the DIDF process. The DIDF only looks at planned capital investments that could be deferred by DERs, but the DIDF may limit the assessment of DERs to the relative economic value of the non-wires alternative relative to capital "wires" investments, such that DERs may not fare as well within this framework. For example, there may be additional benefits of DERs in offsetting onsite diesel consumption that would not be accounted for in the head-to-head comparison. Additionally, if microgrid investments were to be included in the DIDF, CESA seeks to understand whether the utility investment would entail not only distribution capital investments but also generation resources, which may be needed for microgrid configurations. As explained in its GNA, for example, PG&E described how it will build pre-installed interconnection hubs to allow for safe and rapid connection of temporary generation in its Resiliency Zones. Furthermore, the planning standards for "need" of microgrids do not appear to be established, according to CESA's understanding, such that the DIDF may never really capture opportunities for DERs to provide microgrid (resiliency) services. Any insights from PG&E's pilots or Resiliency Zones concept would be helpful in future DPAG meetings, if not the current-year ones. CESA appreciates PG&E's discussion of lessons learned at the DPAG meeting and how it has applied them to this cycle. CESA agrees with the lessons identified but requests some minor terminology suggestion to say that DERs cannot or may struggle to meet "baseload" needs but should not be screened out for being unable to meet "long-duration" needs, which are distinct and should be classified differently. Fewer technologies are able to provide 8-12 hours of duration, but such long-duration needs are still addressable by current and emerging technologies, such as flow batteries, compressed air storage, etc.

CALSSA
What feedback do you have regarding the candidate projects that PG&E proposed for solicitation? CALSSA supports putting these projects out for solicitation. As discussed at the DPAG meeting, PG&E should quantify the energy need as the area of the load curve over the current rating rather than the product of the grid need (the maximum deficiency) and the duration of any need. This will allow storage projects to help meet the need without oversizing the battery capacity. This is important for needs with relatively peaky load shapes, like the Alpaugh circuits.
What feedback do you have regarding the candidate projects that PG&E did not propose for solicitation? CALSSA acknowledges the difficulty that DERs have in meeting a reliability need, particularly those that require islanding capability. Nonetheless, we recommend putting the more cost-effective projects out for bid: FMC 1102 and Camp Evers. As discussed at DPAG meeting, we also recommend putting the three capacity-driven sub-needs embedded in the Estrella project out for solicitation. These sub-needs are well-suited for solar, storage, and DR solutions.
What feedback (if any) do you have on PG&E's DPAG meeting(s) to date? The meeting was very well organized. CALSSA appreciates the professionalism of PG&E's presentation and PG&E staff's cooperation and responsiveness.
What additional information do you need, if any, to determine feasibility of bidding on a project in the 2019 DIDF RFO cycle? N/A
What questions or comments do you have for the Independent Professional Engineer regarding his presentation and review of PGE's GNA/DDOR and candidate deferral prioritization process? The IPE's presentation was very clear and informative.
Any additional questions or comments for PG&E? None

Responses to Energy Division Questions

Questions and PG&E Responses shown on following pages.

(File name: EDRPApplication-2015_DR_ED_019_Q01-18).

PACIFIC GAS AND ELECTRIC COMPANY
Electric Distribution Resources Plan Application 2015
Rulemaking 14-10-003
Application 15-07-006
Data Response

PG&E Data Request No.:	ED_019-Q01-18_Rev01		
PG&E File Name:	EDRPApplication-2015_DR_ED_019-Q01-18_Rev01		
Request Date:	September 24, 2019	Requester DR No.:	9/24/19 (E-Mail)
Date Sent:	November 4, 2019(Original) November 7, 2019(Rev01)	Requesting Party:	Energy Division
PG&E Witness:		Requester:	Robert Peterson

RE: 2019 DPAG/DIDF

QUESTION 01

Why weren't the following four reliability/other needs included in the **2018 GNA or DDOR**?

1. Cholame Between X14 and R96; Emergency line loss; Reliability / Other
2. Cholame Sub DA (day ahead); T-line clearance; Reliability / Other
3. Cholame Sub RT (real time); T-line emergency; Reliability / Other
4. L/S R78 - Templeton 2109; Emergency line loss; Reliability / Other

ANSWER 01

PG&E's 2018 GNA and DDOR reports were the first iteration of the DIDF process and were not a "full" version of the reports as recognized by Decision 18-02-004 and were focused primarily on capacity needs. While the Estrella project was included in the 2018 GNA and DDOR reports, the Real Time reliability needs were not included in the initial cycle. PG&E's 2019 GNA and DDOR reports were the first "full" version and thus the four Real Time reliability needs were examined and included.

QUESTION 02

Describe the following four reliability/other needs in detail. See also the Reference Map, below. Identify the high-side voltages involved and include the specific reliability requirements associated with the needs.

1. Cholame Between X14 and R96; Emergency line loss; Reliability / Other
2. Cholame Sub DA (day ahead); T-line clearance; Reliability / Other

3. Cholame Sub RT (real time); T-line emergency; Reliability / Other
4. L/S R78 - Templeton 2109; Emergency line loss; Reliability / Other

For each need, include the specific **planning standard** that results in the reliability issue. If no planning standard applies, justify the 2019 GNA's/DDOR's identification/inclusion of the reliability needs and the 2019 DDOR's determination that the needs would be addressed by the Estrella planned investment.

Please note, it is our understanding that up to 75 MW of load are allowed to be shed following a N-1 (P1) contingency per the NERC/CAISO planning standards. Additionally, PG&E stated, "PG&E is aware of no distribution planning standard that determines whether a feeder is too long to provide reliable service" in Proponent's Environmental Assessment (PEA), Appendix G, on p. UG-32.

ANSWER 02

PG&E's Guide for Planning Area Distribution Facilities states:

A distribution system consisting of substation banks and interconnected feeders supplying high or medium density (urban or suburban) areas should be engineered to include sufficient interconnections and emergency capability so that, in the event of an outage of any bank or feeder outlet, all service can be restored within a reasonable time by switching.

PG&E does not use NERC/CAISO planning standards to determine distribution reliability needs.

The four reliability needs are described as follows:

1. The Cholame 1101 circuit extends approximately 18 miles west from Cholame Substation and ties to the San Miguel 1104 and Templeton 2109 circuits near the west end of the Cholame 1101 circuit. The Cholame 1101 is a 12 kV circuit and does not have a high-side (transmission) voltage involved. Due to the distance from the Cholame 1101 to adjacent substations (San Miguel and Templeton), normal or emergency load transfers off of Cholame 1101 are limited. Distribution line outages source-side to device X14 disrupt service to all customers beyond X14 until emergency transfers beyond X14 can be completed. Currently the San Miguel 1104 circuit is only able to transfer load from Cholame 1101 beyond device R96 at circuit peak. Additional load transfers from Cholame 1101 to San Miguel 1104 are limited by conductor size and voltage limitations. Load transfers from Cholame 1101 to Templeton 2109 are not possible at circuit peak.

   The planned distribution reinforcement required to create the initial Estrella distribution circuits will strengthen the distribution path between Estrella Substation and the Cholame 1101 circuit. This new circuit from Estrella will have the capability to transfer all load on the Cholame 1101 beyond X14 to Estrella Substation.

2. Cholame Substation is sourced by the Arco-Cholame 70 kV radial tap line. Currently, maintenance on the Arco-Cholame 70 kV line requires that most of the

1,500 customers served from Cholame Substation be notified of planned outages due to the radial transmission source. As detailed in #1 above, only customers beyond device R96 on the Cholame 1101 can typically be served from the San Miguel 1104 circuit during normal scheduled clearances of the Arco-Cholame 70 kV line.

The planned distribution reinforcement required to create the initial Estrella distribution circuits will strengthen the distribution path between Estrella Substation and the Cholame 1101 circuit. This new circuit from Estrella will have the capability to transfer all load on the Cholame 1101 12 kV circuit to Estrella Substation for a normally scheduled clearance of the Arco-Cholame 70 kV line.

3. Cholame Substation is sourced by the Arco-Cholame 70 kV radial tap line. Currently, unplanned outages on the Arco-Cholame 70 kV line disrupt service to the approximately 1,500 customers served from Cholame Substation. As detailed in #1 above, only customers beyond device R96 on the Cholame 1101 can typically be served from the San Miguel 1104 circuit.

   The planned distribution reinforcement required to create the initial Estrella distribution circuits will strengthen the distribution path between Estrella Substation and the Cholame 1101 circuit. This new circuit from Estrella will have the capability to transfer all load on the Cholame 1101 12 kV circuit to Estrella Substation for an unplanned outage on the Arco-Cholame 70 kV line.

4. The Templeton 2109 circuit extends approximately 14 miles from Templeton Substation, into an area of the Paso Robles DPA that has limited and weak ties to adjacent circuits. The Templeton 2109 is a 21 kV circuit and does not have a high-side (transmission) voltage involved. The current configuration results in capacity or voltage issues when attempting to transfer load off of the Templeton 2109 beyond device R78.

   The proposed Estrella Substation site is in the center of the region of the Templeton 2109 that is difficult to transfer to adjacent circuits and will relieve the Templeton 2109 circuit beyond device R78, thus resolving this operational deficiency.

QUESTION 03

The need following the Cholame 70-kV N-1 is quite large (95% overload; see Table 1 below), it exists now, and we assume it has been there for quite some time given the magnitude. How long has PG&E had a Cholame N-1 need (anything above 0). Provide a table showing the **historical** facility rating (MW) and annual % deficiency of the three Cholame needs and the Templeton need over time going back at least to 2009.

ANSWER 03

Table 1 showing the Cholame 70 kV N-1 need has been revised with updated calculations for % Deficiency at system peak. Note, the deficiencies shown in Table 1 are the need relative to the Facility Rating.

TABLE 1: PG&E 2019 GNA (Revised)
Appendix 6.6: GNA Results - Reliability / Other Needs

Facility Name	Primary Driver	Distribution Service Required	Anticipated Need Date	2019 Facility Rating (MW)	2019 Deficiency (%)	2020 Deficiency (%)	2021 Deficiency (%)	2022 Deficiency (%)	2023 Deficiency (%)
Cholame Between X14 and R96	Emergency line loss	Reliability / Other	2024	12.40	12%	12%	12%	12%	12%
Cholame Sub DA	T-line clearance	Reliability / Other	2024	27.16	45%	45%	45%	44%	44%
Cholame Sub RT	T-line emergency	Reliability / Other	2024	27.16	45%	45%	45%	44%	44%
L/S R78 - Templeton 2109	Emergency line loss	Reliability / Other	2024	21.62	37%	38%	39%	39%	39%

Cholame Substation has a peak demand heavily influenced by agricultural water pumping. As such, loads on the substation vary year-to-year and have varied from 9.1 MW in 2010 up to 12.47 MW in 2018. The current operational constraints of relieving Cholame Substation load from the adjacent San Miguel Substation at system peak have not significantly varied historically. Similarly, due to the location of the extremities of the Templeton 2109 circuit and lack of strong ties to adjacent circuits, available transfers off of the Templeton 2109 have not substantially varied historically.

The tables below show the historical Facility Rating (MW) and annual % Deficiency of the three Cholame needs and the Templeton need over time going back at least to 2009. Note, the % Deficiency for the tables below are the need relative to the Peak Demand.

Cholame beyond X14:

Year	Cholame 1101 Facility Rating (MW)	Cholame 1101 beyond X14 Peak Demand (MW)	Potential Transfer to San Miguel (MW)	Net Need (MW) [Peak Demand-Transfer]	% Deficiency [Net Need/ Peak Demand]
2018	12.31	2.92	1.5	1.42	49%
2017	12.31	2.96	1.5	1.46	49%
2016	12.31	3.29	1.5	1.79	54%
2015	12.31	2.57	1.5	1.07	42%
2014	12.31	2.89	1.5	1.39	48%
2013	12.31	2.63	1.5	1.13	43%
2012	12.31	2.84	1.5	1.34	47%
2011	12.31	2.68	1.5	1.18	44%
2010	12.31	3.02	1.5	1.52	50%
2009	12.31	3.48	1.5	1.98	57%

Cholame Substation:

Year	Cholame Facility Rating (MW)	Cholame Peak Demand (MW)	Potential Transfer to San Miguel (MW)	Net Need (MW) [Peak Demand- Transfer]	% Deficiency [Net Need/ Peak Demand]
2018	27.16	12.47	1.5	10.97	88%
2017	27.16	11.75	1.5	10.25	87%
2016	27.16	11.46	1.5	9.96	87%
2015	27.16	9.5	1.5	8	84%
2014	27.16	10.45	1.5	8.95	86%
2013	27.16	10.13	1.5	8.63	85%
2012	27.16	9.32	1.5	7.82	84%
2011	27.16	8.3	1.5	6.8	82%
2010	27.16	9.1	1.5	7.6	84%
2009	27.16	9.7	1.5	8.2	85%

Templeton 2109 beyond R78:

Year	Templeton 2109 Facility Rating (MW)	Templeton 2109 beyond R78 Peak Demand (MW)	Potential Transfer to Paso Robles (MW)	Net Need (MW) [Peak Demand- Transfer]	% Deficiency [Net Need/ Peak Demand]
2018	21.62	7.48	1.1	6.38	85%
2017	21.62	8.68	1.1	7.58	87%
2016	21.62	7.69	1.1	6.59	86%
2015	21.62	7.39	1.1	6.29	85%
2014	21.62	6.34	1.1	5.24	83%
2013	21.62	7.28	1.1	6.18	85%
2012	21.62	7.03	1.1	5.93	84%
2011	21.62	6.08	1.1	4.98	82%
2010	21.62	7.86	1.1	6.76	86%
2009	21.62	7.26	1.1	6.16	85%

QUESTION 04

Based on comments made at the 2019 PG&E DRP DPAG, our understanding is that the cause of the Cholame reliability issues is an N-1 outage of the 70-kV line that powers Cholame (from Arco Substation). To what extent would Estrella Substation as currently described in the PTC Application solve the entire Cholame 70-kV N-1 need. Be specific about the amount of **any remaining need**, if it would exist.

For example, according to the June 2018 filing for the Formal Application (PEA, Appendix G, Table 7), Estrella Substation as proposed would unload Cholame Substation by 2.10 MW, but the N-1 need per the 2019 GNA would be closer to 12 MW.

Furthermore, PEA Appendix G states, "The proposed project provides a future opportunity to add an **additional transmission line to Cholame Substation** to create a looped circuit to improve reliability and operational flexibility on the 70 kV system. This line would likely be constructed within 2 to 3 years after Estrella Substation is built" on p. UG-27. Hence, to solve the Cholame N-1 contingency, a new 70-kV line would be required (17 miles long). If this need is real as of 2019 (and prior to that) and directly linked to completion of Estrella Substation, it seems that it should have been part of the original project description for Estrella Substation. However, we believe that the CAISO would also need to validate the Cholame N-1 need, possibly through their annual transmission planning process (p. UG-40). Please discuss how (and when) this need will be addressed by PG&E and the CAISO.

A battery solution to the Cholame N-1 need is also discussed (p. UG-28), but if the need is in fact 24 to 48 hours in duration per the 2019 GNA, this does not appear to be feasible. This also appears to be PG&E's finding, see p. UG-39. In any case, a new 70-kV line is not the same as building out the distribution system. Hence, decoupling the Cholame-N-1 need from the 2019 DDOR Estrella Planned investment should be considered. The capacity needs could be addressed by battery storage and should be considered by PG&E in the 2019 DDOR separately than the Cholame N-1 reliability needs.

ANSWER 04

The Estrella Substation Project, as approved by CAISO and as described in the PTC application was not designed to address the Cholame 70 kV radial feed arrangement and resulting N-1 issue. However, the Estrella Substation Planned Investment, which consists of distribution facilities as examined in PG&E's 2019 DDOR, is expected to provide distribution system operational flexibility and distribution reliability benefits whenever Cholame 70 kV completely loses its power source. The Planned Investment for Estrella Substation would be able to pick-up approximately 5 MW of the 14 MW the substation is forecasted to serve.

It is correct that a new 70 kV transmission line from the proposed Estrella Substation to the existing Cholame 70 kV Substation would fully solve the Cholame N-1 contingency and would need to be brought forward to CAISO for review and approval, whether as part of the original project or a later proposal. PG&E has not submitted nor is it currently planning to submit a request to CAISO for review and approval of a new 70 kV line between proposed Estrella Substation and existing Cholame Substation, nor is this hypothetical new 70 kV line part of the proposed Estrella Substation project.

As context, PG&E provided the 2- to 3-year time frame in response to data requests from Energy Division in the Estrella PTC proceeding regarding if and when PG&E would construct a 70-kV line between proposed Estrella Substation and existing Cholame Substation. In a data request dated June 27, 2017, Energy Division asked PG&E to "[d]iscuss the timing of future plans to connect existing Cholame Substation to the proposed Estrella Substation with a transmission line to better serve the Cholame DPA." PG&E responded on August 28, 2017, that "[t]he timing is unknown, but the proposed project provides the opportunity to add an additional transmission line to Cholame Substation in the future to create a looped circuit to improve reliability and operational flexibility." In a subsequent data request dated February 27, 2018, Energy Division asked PG&E: "[i]f the Estrella Substation is constructed, what is a reasonable timeframe to assume that a 70-kV line to Cholame Substation would be constructed." PG&E responded on May 2, 2018 that "Section IV.B in the Updated Appendix G provides a reasonable timeframe to assume that a 70-kV line to existing Cholame Substation will be constructed. This estimate is preliminary and subject to change." Section IV.B in the Updated Appendix G contains the "2 to 3 year" statement quoted above. Thus, the context for this statement makes clear that the timing for such a 70-kV line is unknown and that the 2 to 3 year timeframe was provided at Energy Division's request for information to use in their CEQA analysis for the project. PG&E did not include the time needed to seek CAISO approval or a Permit to Construct from the CPUC in the 2 to 3 year timeframe, which in retrospect may have created confusion.

However, as mentioned above, PG&E is not considering whether to build such a 70-kV line at this time. Before arriving to such conclusion and before submitting to CAISO for approval, PG&E's transmission department would need to evaluate if there may be a better option such as a line to a substation that may be closer to Cholame, battery storage or any other solutions. But again, at this point there are no plans to bring forward such a proposal to CAISO. Regardless, the Expected Performance and Operation Requirements identified in PG&E's 2019 DDOR are the requirements for DERs to defer the distribution components of the Estrella Substation Planned Investment, not a new 70-kV line. The reliability and capacity needs identified in PG&E's 2019 DIDF are both met by the Estrella Substation, and thus the capacity needs are not addressed separately in PG&E's 2019 DDOR.

QUESTION 05

To what extent could **distribution system back-ties** be activated/installed to solve the Cholame N-1 need via existing PR DPA or other DPA distribution infrastructure. If not, what would be the remaining deficiency (MW and duration).

ANSWER 05

PG&E has not designed a hypothetical distribution Planned Investment alternative to solve the Cholame N-1 need other than the Estrella Substation. However, preliminary engineering analysis has indicated extensive reconductoring and upgrades of transformer banks (as identified below) would be necessary that would exceed the scope and cost of the distribution components of the Estrella Substation Planned Investment.

Cholame Substation consists of two distribution transformer banks, Cholame Bank 1 and Cholame Bank 2. Cholame Bank 1 serves the Cholame 1101 circuit. Cholame Bank 2 serves the Cholame 2102 circuit. The Cholame 1101 circuit has ties to the San Miguel 1104 circuit (served from San Miguel Bank 1) and the Templeton 2109 circuit (served from Templeton Bank 2), both at the west end of the Cholame 1101 circuit. The Cholame 2102 circuit has two ties to the Cholame 1101 circuit, but no ties to other circuits or substations within the Paso Robles DPA nor any other DPA in the area.

San Miguel Substation is approximately 26 circuit miles from Cholame Substation. Historically, the San Miguel 1104 circuit has been able to offload the western portion of the Cholame 1101 circuit up to device R96. Additional load transfers from the Cholame 1101 to the San Miguel 1104 have been limited due to loading levels on existing distribution facilities and voltage issues.

In addition to the fact that the distribution tie between San Miguel and Cholame Substations is lengthy and consists of limited capacity conductors, San Miguel Bank 1 is currently forecast to be loaded 3.6 MW above its summer normal capability. No additional load can be served from San Miguel Bank 1 during times of system peak. Also, the magnitude of projected overload on San Miguel Bank 1 further reduces times outside of system peak when load from the Cholame 1101 could be served from the San Miguel 1104. Conceptually, if the entire distribution route between San Miguel Substation and Cholame Substation were to be reinforced, the ability of San Miguel to relieve Cholame at system peak would still be limited by available capacity on San Miguel Bank 1.

Templeton Substation is approximately 32 circuit miles from Cholame Substation. While the distribution facilities of the Templeton 2109 circuit between Templeton Substation and the tie to the Cholame 1101 consist of larger capacity conductors than the San Miguel-Cholame tie, the path is approximately twice the distance than that of the San Miguel-Cholame tie (7 miles vs. 14 miles). Additionally, the current forecast projects Templeton Bank 2 to have 2.7 MW available capacity, with load growth projected to exceed the distribution bank rating in 2026. Given the projected load growth on Templeton Bank 2 within the 10-year forecast horizon, the ability of the Templeton 2109 circuit to relieve Cholame Substation is limited due to the lack of available capacity on the distribution transformer bank.

QUESTION 06

If the proposed **Estrella Substation is not constructed**, identify ways in which PG&E would solve the Cholame 70-kV N-1 issue? To what extent would PG&E violate a NERC/CAISO standard if they do not resolve the issue, and the outage occurred, resulting in load shedding? Describe the penalty for this violation and provide an estimated dollar amount.

ANSWER 06

A single line outage of the 70-kV line to Cholame 70 kV Substation results in the loss of power to the substation and the direct loss of about 12 MW of current customer load which creates a customer reliability issue for those customers. PG&E does not have any plans at this time to solve the Cholame 70 kV N-1 issue whether the proposed Estrella Substation is constructed or not. The single line outage does not result in any impacts to the transmission system and as such does not result in any NERC or CAISO reliability standards violations.

QUESTION 07

Was the **Cholame 70-kV N-1 considered in the 2013 TPP** process that resulted in CAISO's approval of the Estrella project? Was this N-1 discussed with the CAISO any time prior to or since their approval of the Estrella project?

Does PG&E plan to present the Cholame 70-kV N-1 to the CAISO in the current TPP or a future TPP? If not, why not?

ANSWER 07

The Cholame 70 kV N-1 situation has not been discussed with the CAISO in association to the Estrella Substation project before or after its approval. Further, PG&E at this point in time does not plan to present a solution to the Cholame 70 kV N-1 situation as part of this cycle of the TPP or a future cycle because currently there is no NERC or CAISO reliability standard violations.

QUESTION 08

a. Table 2, below, shows a screen capture from the draft, updated PG&E 2019 GNA/DDOR filing (not yet refiled). The draft update still has discrepancies. For example, The GNA indicates that **San Miguel Bank 1** need reaches 1.68MW (2023) in the five-year planning window, not 3.6MW.

b. In addition, **Templeton Bank 3** exceeds it's rating by only 0.12 MW (2022) and not 1.1MW. Based on this low exceedance, which does not occur in 2023, it appears that Templeton Bank 3 should not be included as an Estrella Planned Investment capacity need at all.

ANSWER 08

The GNA and DDOR reports use different planning horizons when determining the deficiency/grid need (DER service requirements). This is described in Section 5, DER Distribution Service Requirements, of the GNA report as follows:

"The basis for the DER distribution service requirements was determined from the highest overload for the period from the in-service date until the end of the 10-year forecast horizon. Therefore, the distribution service requirement may be based on a later year than need included in the GNA or in the Planned Investments list (Appendix A), which used a 5-year forecast as the study horizon for identifying grid needs."

a. The summer normal capacity of San Miguel Bank 1 is 15.84 MW. Due to the projected overload on San Miguel Bank, a +10% temporary re-rate on the distribution transformer bank has been granted until Estrella Substation can be constructed and relieve San Miguel Substation. The temporary re-rate on San Miguel Bank 1 raises the summer normal capacity to 17.42 MW.

   The peak projected load for San Miguel Bank 1 within the 5-year forecast is 19.1 MW in 2023, a 3.26 MW deficiency when evaluated against the summer normal capability of San Miguel Bank 1. The GNA reported the summer normal capacity of San Miguel Bank 1 as 17.42 MW, which is the re-rated capability of the transformer bank, not the summer normal capability. Therefore, the GNA reports a deficiency of 1.68 MW against the 17.42 MW re-rate.

The peak projected load on San Miguel Bank 1 within the 10-year forecast horizon is 19.44 MW in 2028, a 3.6 MW overload.

b. The peak projected load for Templeton Bank 3 within the 5-year forecast is 44.67 MW, or a 0.12 MW deficiency in 2023). The peak projected load for Templeton Bank 3 within the 10-year forecast is 45.63 MW, or a 1.08 MW (rounded to 1.1 MW) deficiency in 2027.

QUESTION 09

Please break out the 7 grid needs into their relative grid-need components, consider only the three capacity components for deferral (e.g., Paso Robles 1104, San Miguel Bank 1, and Templeton Bank 3, which are the three **remaining capacity-driven components**) and how that impacts the need and scoring metrics of the total project. Show all calculations and the new Tier ranking.

*Remove Templeton Bank 3 as well, depending on PG&E's position regarding Item 8b. above.

ANSWER 09

The 7 grid needs are broken out in PG&E's published DDOR report. As noted in PG&E's response to Question 4, the reliability and capacity needs identified in PG&E's 2019 DIDF are both met by the Estrella Substation, and thus the capacity needs are not addressed separately in PG&E's 2019 DDOR. However, as presented in the DPAG webinar, below is the Hypothetical Estrella ranking (with only the capacity-driven components) and analysis below. This scenario would have the Hypothetical Estrella ranked as a Tier 2 Candidate Deferral Opportunity.

As PG&E responded to Question 8b, Templeton Bank 3 is a capacity-driven need and so is still included in the Hypothetical Estrella ranking.

Tier	Candidate Deferral	Cost Effectiveness			Forecast Certainty			Market Assessment				
		Unit Cost ($k)	LNBA ($/kW-yr)	LNBA ($/MWh/yr)	In-Service Date	SCADA Avail. (Y/N)	Cust-omers	Real Time (RT) or Day Ahead (DA)	Days/ Year	# of Grid Needs	Hours/ Call	Over-capacity (%)
1	Alpaugh New Feeder	$3,600	$89	$88	2022	Y	2650	DA	113	1	9	38%
1	Calflax Bank 2	$6,070	$88	$60	2023	Y	228	DA	CC	1	CC	CC
1	Santa Nella New Bank & Feeder	$7,256	$55	$78	2022	Y	973	DA	122	4	7	36%
2	Camp Evers 2107	$1,720	$202	$2,100	2022	Y	6370	RT+Islanding	8	1	12	3%
2	FMC 1102	$1,700	$232	$4,830	2023	Y	3422	RT	4	1	12	4%
2	Brentwood 2105	$640	$59	$612	2022	Y	2841	RT+Islanding	8	1	12	6%
2	Estrella Substation (hypothetical)	$18,500	$209	$293	2024	Y	2738	DA	122	3	9	21%
3	Pueblo Bank 3	$6,936	$21	$110	2022	Y	9952	RT	8	1	24	52%
3	Oceano 1106	$425	$18	$64	2022	Y	6811	RT+Islanding	12	1	24	8%
3	Rosedale 2102	$400	$24	$84	2022	Y	1378	RT	12	1	24	9%
3	Rob Roy 2105	$500	$18	$63	2022	Y	8056	RT+Islanding	12	1	24	13%
3	Peabody 2106	$390	$8	$28	2022	Y	2845	RT+Islanding	CC	1	CC	CC
3	Madison 2101	$105	$13	$45	2022	Y	2068	RT+Islanding	CC	1	CC	CC
3	Martin SF H 1108	$180	$9	$33	2022	Y	6716	RT+Islanding	12	1	24	8%
3	Martin SF H 1107	$150	$4	$15	2022	Y	7090	RT+Islanding	12	1	24	18%
3	Avenal 2101	$65	$6	$21	2022	Y	1948	RT+Islanding	CC	1	CC	CC
3	Edenvale 2108	$95	$7	$24	2022	Y	6630	RT+Islanding	12	1	24	7%
3	Dairyland 1110 New Feeder	$3,887	$96	$24	2022	Y	518	DA	168	1	24	34%

QUESTION 10

The "need date" is identified as 2024, but two of the capacity needs first occur in 2019. Since the need date appears to be based on the operational date of a potential new Estrella Substation (and somewhat arbitrary), please assume a 2022 need date, which would be optimal for DER considerations.

For comparative purposes, recalculate the **Forecast Certainty** metric with 2022 instead of 2024. Show all calculations.

ANSWER 10

The basis of the Prioritization Metrics, including the Forecast Certainty Metric, is the In-Service Date of the Planned Investment, which is why the DDOR lists 2024 as the Forecasted Need Date.

Under a hypothetical assumption of a 2022 In-Service Date for Estrella, the Forecast Certainty metric has changed from red (low) to blue (high). The overall tier ranking has changed from Tier 3 to Tier 2. Please see below for details.

Hypothetical 2022 Estrella, Prioritization Metrics and Rankings

Tier	Candidate Deferral	In-Service Date	Deficiency (MW)	Prioritization Metrics: Cost Effectiveness	Prioritization Metrics: Forecast Certainty	Prioritization Metrics: Market Assessment
1	Alpaugh New Feeder	2022	4.4			
	Calflax Bank 2	2023	CC			
	Santa Nella New Bank & Feeder	2022	9.3			
2	Camp Evers 2107	2022	0.9			
	FMC 1102	2023	0.8			
	Brentwood 2105	2022	1.2			
	Estrella Substation (hypothetical)	2022	19.4			
3	Pueblo Bank 3	2022	23.2			
	Oceano 1106	2022	1.2			
	Rosedale 2102	2022	1.8			
	Rob Roy 2105	2022	3.0			
	Peabody 2106	2022	CC			
	Madison 2101	2022	CC			
	Martin SF H 1108	2022	1.0			
	Martin SF H 1107	2022	1.8			
	Avenal 2101	2022	CC			
	Edenvale 2108	2022	1.5			
	Dairyland 1110 New Feeder	2022	4.5			

Hypothetical 2022 Estrella, Basis for Prioritization Metrics

Tier No	Candidate Deferral	Cost Effectiveness			Forecast Certainty			Market Assessment				
		Unit Cost ($k)	Estimated LNBA ($/kW-yr)	Estimated LNBA ($/MWh-yr)	Forecasted Need (Year)	SCADA Available (Y/N)	Customers on Asset	Real Time (RA) or Day Ahead (DA)	Days/ Year	Number of Grid Needs	Hours/Call	Overcapacity (%)
1	Alpaugh New Feeder	$3,600	$89	$88	2022	Y	2650	DA	113	1	9	38%
	Calflax Bank 2	$6,070	$88	$60	2023	Y	228	DA	CC	1	CC	CC
	Santa Nella New Bank & Feeder	$7,256	$55	$78	2022	Y	973	DA	122	4	7	36%
2	Camp Evers 2107	$1,720	$202	$2,100	2022	Y	6370	RT+Islanding	8	1	12	3%
	FMC 1102	$1,700	$232	$4,830	2023	Y	3422	RT	4	1	12	4%
	Brentwood 2105	$640	$59	$612	2022	Y	2841	RT+Islanding	8	1	12	6%
	Estrella Substation (hypothetical)	$18,500	$67	$241	2022	Y	225	RT+Islanding	122	7	48	39%
3	Pueblo Bank 3	$6,936	$21	$110	2022	Y	9952	RT	8	1	24	52%
	Oceano 1106	$425	$18	$64	2022	Y	6811	RT+Islanding	12	1	24	8%
	Rosedale 2102	$400	$24	$84	2022	Y	1378	RT	12	1	24	9%
	Rob Roy 2105	$500	$18	$63	2022	Y	8056	RT+Islanding	12	1	24	13%
	Peabody 2106	$390	$8	$28	2022	Y	2845	RT+Islanding	CC	1	CC	CC
	Madison 2101	$105	$13	$45	2022	Y	2068	RT+Islanding	CC	1	CC	CC
	Martin SF H 1108	$180	$9	$33	2022	Y	6716	RT+Islanding	12	1	24	8%
	Martin SF H 1107	$150	$4	$15	2022	Y	7090	RT+Islanding	12	1	24	18%
	Avenal 2101	$65	$6	$21	2022	Y	1948	RT+Islanding	CC	1	CC	CC
	Edenvale 2108	$95	$7	$24	2022	Y	6630	RT+Islanding	12	1	24	7%
	Dairyland 1110 New Feeder	$3,887	$96	$24	2022	Y	518	DA	168	1	24	34%

Combining the two scenarios from Q9 and Q10 (Capacity only projects and assuming a 2022 In-Service date) would have the Hypothetical Estrella ranked as a Tier 1 Candidate Deferral Opportunity. Please see below for details.

Hypothetical 2022 and Capacity only - Estrella, Prioritization Metrics and Rankings

Tier	Candidate Deferral	In-Service Date	Deficiency (MW)	Prioritization Metrics		
				Cost Effectiveness	Forecast Certainty	Market Assessment
1	Alpaugh New Feeder	2022	4.4			
	Calflax Bank 2	2023	CC			
	Santa Nella New Bank & Feeder	2022	9.3			
	Estrella Substation (hypothetical)	2022	5.9			
2	Camp Evers 2107	2022	0.9			
	FMC 1102	2023	0.8			
	Brentwood 2105	2022	1.2			
3	Pueblo Bank 3	2022	23.2			
	Oceano 1106	2022	1.2			
	Rosedale 2102	2022	1.8			
	Rob Roy 2105	2022	3.0			
	Peabody 2106	2022	CC			
	Madison 2101	2022	CC			
	Martin SF H 1108	2022	1.0			
	Martin SF H 1107	2022	1.8			
	Avenal 2101	2022	CC			
	Edenvale 2108	2022	1.5			
	Dairyland 1110 New Feeder	2022	4.5			

Hypothetical 2022 and Capacity only - Estrella, Basis for Prioritization Metrics

Tier No	Candidate Deferral	Cost Effectiveness			Forecast Certainty			Market Assessment				
		Unit Cost ($k)	Estimated LNBA ($/kW-yr)	Estimated LNBA ($/MWh-yr)	Forecasted Need (Year)	SCADA Available (Y/N)	Customers on Asset	Real Time (RA) or Day Ahead (DA)	Days/ Year	Number of Grid Needs	Hours/Call	Overcapacity (%)
1	Alpaugh New Feeder	$3,600	$89	$88	2022	Y	2650	DA	113	1	9	38%
	Calflax Bank 2	$6,070	$88	$60	2023	Y	228	DA	CC	1	CC	CC
	Santa Nella New Bank & Feeder	$7,256	$55	$78	2022	Y	973	DA	122	4	7	36%
	Estrella Substation (hypothetical)	$18,500	$219	$307	2022	Y	2738	DA	122	3	9	21%
2	Camp Evers 2107	$1,720	$202	$2,100	2022	Y	6370	RT+Islanding	8	1	12	3%
	FMC 1102	$1,700	$232	$4,830	2023	Y	3422	RT	4	1	12	4%
	Brentwood 2105	$640	$59	$612	2022	Y	2841	RT+Islanding	8	1	12	6%
3	Pueblo Bank 3	$6,936	$21	$110	2022	Y	9952	RT	8	1	24	52%
	Oceano 1106	$425	$18	$64	2022	Y	6811	RT+Islanding	12	1	24	8%
	Rosedale 2102	$400	$24	$84	2022	Y	1378	RT	12	1	24	9%
	Rob Roy 2105	$500	$18	$63	2022	Y	8056	RT+Islanding	12	1	24	13%
	Peabody 2106	$390	$8	$28	2022	Y	2845	RT+Islanding	CC	1	CC	CC
	Madison 2101	$105	$13	$45	2022	Y	2068	RT+Islanding	CC	1	CC	CC
	Martin SF H 1108	$180	$9	$33	2022	Y	6716	RT+Islanding	12	1	24	8%
	Martin SF H 1107	$150	$4	$15	2022	Y	7090	RT+Islanding	12	1	24	18%
	Avenal 2101	$65	$6	$21	2022	Y	1948	RT+Islanding	CC	1	CC	CC
	Edenvale 2108	$95	$7	$24	2022	Y	6630	RT+Islanding	12	1	24	7%
	Dairyland 1110 New Feeder	$3,887	$96	$24	2022	Y	518	DA	168	1	24	34%

QUESTION 11

Clearly explain why the LNBA Value ($/KW-yr) is $558 for the Planned Investment listing for Estrella but only $51 for the Candidate Deferral Listing. Show all calculations.

For comparative purposes, Recalculate the **Cost-Effectiveness** metric with $558 instead of $51. Show all calculations.

ANSWER 11

In the Planned Investment table from August 15th, the LNBA value for Estrella incorrectly omitted the reliability needs. The LNBA value has been corrected to $76 and is included in the republished DDOR report. The Cost Effectiveness metric for Estrella is based on the LNBA value from the Candidate Deferral listing and has been updated in PG&E's republished DDOR report.

QUESTION 12

Assuming the Estrella Substation is constructed as proposed, provide the full **scope of both the distribution AND transmission work (itemized)** that would be necessary to address the four new Cholame and Templeton reliability/other needs in the 2019 GNA/DDOR. We note that the distribution work alone adds up to $18.5 million per the 2019 DDOR filing.

ANSWER 12

No work at the Estrella Substation as proposed is required to address solely the four reliability needs in the 2019 GNA/DDOR. The location of the proposed Estrella Substation was chosen to achieve the distribution objectives stated in the Project Description of the Proponent's Environmental Assessment (PEA), which are to: "Provide a location for future 21 kV distribution facilities with a 230/70 kV source near the anticipated growth areas in northern Paso Robles to efficiently add distribution capacity and improve service reliability when required in the Paso Robles Distribution Planning Area [DPA]." (PEA at p. 2-2.) As further described in PEA Appendix G, "Distribution Need Analysis," the proposed future distribution facilities would increase available capacity in the Paso Robles DPA, and increase reliability and operational flexibility in the DPA by reducing feeder length and providing back-ties to existing distribution feeders from San Miguel, Paso Robles, and Templeton substations. (Appendix G at pp. UG-26 to -28.) See also Figures 4A, 4B and 4C in PEA Appendix G, which show how a new Estrella distribution feeder would tie into the Cholame 1101 circuit and provide capacity and reliability benefits to the Cholame DPA. In other words, undertaking the distribution and transmission work at Estrella Substation needed to increase distribution capacity and reliability in the Paso Robles DPA will also address these four reliability needs.

Below is a description of the type and quantity of distribution and transmission work that is described in the PEA as "future distribution facilities" at the Estrella Substation (PEA at pp. 2-21 to -22, Figure 2-10). Note that these future distribution facilities are included in the PEA as part of the "project" for the environmental analysis under the California Environmental Quality Act. However, PG&E did not request authority to construct the future distribution facilities as part of the Joint Application for Permits to Construct jointly filed with Horizon West Transmission, LLC, on January 25, 2017 because, at the time, it forecast that the future distribution facilities would be needed at some point in the next 5 to 15 years, which was well after the planned in-service date for Estrella Substation of May 2019.

Assuming the Estrella Substation is constructed as proposed in the Joint Application for Permits to Construct (which only includes transmission-level facilities), the additional distribution and transmission equipment needed at Estrella Substation to construct the future distribution facilities described in the PEA is as follows:

- Five 70 kV Group Operated Air Break Switches
- Two 70 kV SF_6 Insulated Circuit Breakers
- One three-phase 70/21 kV 30 Megavolt Amperes (MVA) transformer
- One four-bay 21 kV Aluminum Bus Structure
- Four 21 kV Vacuum Insulated Circuit Breakers

The following distribution line work would also be needed:

- 3,000’ new underground cable in new conduit
- 5,000’ new underground cable in existing conduit
- 7,700’ new overhead conductor
- 44,200’ replaced overhead conductor
- Three new 21/12 kV step-down transformers
- 115 replaced distribution service transformers

QUESTION 13

SDG&E’s 2019 GNA included only 10 planned investments with in-service dates of 2020 and 2021.

a. Were any of these planned investments showing as needed in the 2018 GNA and if yes what were their in service dates? Are there any other patterns of changes between the 2019 and 2018 GNA that warrant further examination.

b. Why are there no planned investments beyond 2022? What explains this? Will the next SDG&E GRC likely see a drop in Distribution capital funding levels being requested?

c. IPE can you validate that there are no grid needs beyond 2022?

d. IPE can you validate that none of the 10 planned investments are viable as DER deferrals?

e. IPE what is your view of SDG&E's prioritization ranking methods compared with the equivalent methods used by PG&E and SCE?

ANSWER 13

This question is not applicable to PG&E.

QUESTION 14

SCE's 2019 GNA has a unique project ID for each grid need/planned investment to help cross walk to GRC. Does PG&E and SDG&E have the same?

ANSWER 14

PG&E has a unique project ID, called a Planning Order (PO) for all projects in the GRC with forecasted spending greater than $3M. All Major Work Category (MWC) 46 projects (substation capacity) also have a specific PO. MWC 06 projects (line capacity) associated with a MWC 46 project have a specific PO. MWC 06 projects less than $3M do not have a specific PO, but instead share a bucket PO with other projects of that project type in that division. Planning Orders are listed in Exhibit (PG&E-4), Chapter 13, WP table 13-12, of PG&E's 2020 GRC application (A.18-12-009).

In PG&E's DRP filings, projects are identified in the DDOR, not in the GNA, since not all grid needs may require a planned investment (and potentially be identified in a GRC). In the DDOR, projects are listed by name. At this time, PG&E Planning Orders are not listed in the 2019 DDOR.

QUESTION 15

For each category of planned investment (capacity, voltage, reliability, back-tie, capacity) please quantify:

- The capacity of need in the 2019 GNA
- The capital cost estimated in the 2019 GNA/DDOR, or provide the capital cost if not included in the GNA/DDOR
- The capital cost in the most recent GRC for the category of investment.

ANSWER 15

- The summed capacity of need in the 2019 GNA is 118.86 MW. This was obtained by adding the 2019 Deficiency MW Column in the GNA Capacity table (Appendix 6.5: GNA Results – Demand Forecast and Bank/Feeder Capacity Needs).

- The capital cost estimated in the 2019 GNA/DDOR is listed below:

Distribution Service Required	Project costs based on unit costs
Capacity	$203.7M
Reliability/Other	$72.96M
Voltage*	$7.12M
Total	**$283.78M**

*This capital cost is for the Voltage only projects, $7.83M have both Voltage and Capacity projects, and has been included in the Capacity capital cost

- In the most recent GRC, forecasted capital expenditures for capacity line work (Major Work Category 06), in escalated dollars, for the years 2018 to 2022 is $449.7M. See Chapter 13 Workpaper table 13-9, line 17. The forecasted capital expenditures for capacity substation work (Major Work Category 46), in escalated dollars, for the years 2018 to 2022 is $167.0M See Chapter 13 Workpaper Table 13-9, line 23.

  Please note, Chapter 13 GRC amounts are not directly comparable with costs included in the DDOR because the GRC includes project costs prior to the DDOR timeframe, while the DDOR includes project costs subsequent to the GRC timeframe. In addition, Chapter 13 of the GRC includes projects that are not DER-deferrable such as projects that add visibility to capacitor banks and regulators. Note that most Major Work Category (MWC) 06 projects (capacity line work) and most projects under $3M are not explicitly listed in Chapter 13 of the GRC.

QUESTION 16

How does PV and other DER penetration affect voltage rise in planning assumptions that inform the voltage-related planned investments in your 2019 GNA/DDOR? How do smart inverter functions (e.g. volt/var, volt-watt etc) required by all inverter-based DERs affect voltage impacts of DER penetration in this GNA/DDOR and in the future.

ANSWER 16

The load and/or generation of PV and other DERs are included in the forecast used to perform voltage studies on line sections. DER growth is disaggregated at the feeder level and then applied uniformly to individual line sections.

None of the projects in the 2019 DDOR are the result of overvoltage from DER penetration.

PG&E currently does not see any evidence at this time that Smart Inverters are affecting PG&E primary voltage. It has been shown that secondary voltage beyond the distribution transformer could benefit from the Smart Inverter functionality. Until Smart

Inverters establish themselves more throughout PG&E territory, we will be assuming our standard secondary voltage drop from our Primary to Secondary system. PG&E is open to revisiting the criteria in the future and adjusting as needed to inform voltage-related investments.

QUESTION 17

For any of the planned investments that have in-service dates of 2021 or sooner, has the IOU considered if a DER solution initiated by the IOU is the lowest cost way to address the need? Please provide details of all examples where DERs were considered. If DERs were not considered explain why.

ANSWER 17

Yes, PG&E has considered DER solutions via the Distribution Investment Deferral Framework (DIDF). While Planned Investments with in-service dates of 2021 or sooner were screened out of consideration as Candidate Deferral Opportunities in the 2019 DDOR, the DIDF is an annual cycle and thus these planned investments are considered in prior cycles. For example, Huron Bank 1 has an in-service date of 2021. While it was screened out in the 2019 DDOR, it was included as Tier 1 candidate deferral in the 2018 DDOR and is currently out for solicitation for DER solutions.

QUESTION 18

IPE, for each IOU please offer your analysis of whether you agree with the ranking criteria of which DDOR projects will be included in an RFO. Please comment if you think any projects should be added or subtracted from the Tier 1 category.

ANSWER 18

This question is not applicable to PG&E.

Appendix B Data Requests and Responses

The IPE received many sets of data in response to requests for information to PG&E. Listed below are the types of data provided. In most cases these data sets are spreadsheets, PDFs, Power Point presentations or Word documents. These documents are provided as separate documents from the body of this report.

B.1 Data Requests

1. **7/12 – Data Request 1** – Copy of PPT Presentation to LFWG on Disaggregation
2. **8/5 – Data Request 2** – CEC Load and Forecasting Data Used by PG&E
3. **8/19 – Data Request 3** –
   a. Full set of unit costs, and a description as to how they were developed, that were used for determining the costs of the traditional projects included in DDOR. For those projects that are more developed, please provide any changes from the unit costs that are applicable to these advanced projects
   b. Data and spreadsheet used for the calculation of the LNBA values for each project.
   c. Tables in the DDOR Report in spreadsheet format (if they exist) for Appendix B DDOR Opportunities and Appendix C Basis for Prioritization Metrics
4. Various email and verbal requests and responses are listed in the list below

B.2 List of Responses

Listed below are files or groups of files that PG&E provided to the IPE in response to the IPE's requests.

Some response documents have been designated by PG&E as containing information considered as confidential per the 15/15 rule. This data has been redacted in this Public Version of the Report. The documents with redacted data are highlighted in green below.

Date	File Name
7/12/19	DR1 07.12.19 - Presentation provided which includes IOU joint methodology
8/5/19	DR2 08.14.19 - PG&E provided link to CEC Files
8/22/19	DR3 08.22.19 - PG&E provided GNA, LNBA and DDOR spreadsheets. PGE_DDOR_2019_081519_Confidential Simplified LNBA Tool V3.5-2019-8-15-2019-CandiateDeferal

8/23/19	DR3 08.23.19 – PG&E provided GRC Chapter 13
8/28/19	DR3 08.28.19 – PG&E – PG&E_DDOR_SOW_Confidential
9/9/19	DR 09.09.19 Screenshots for IPE Calflax Bank 1
9/10/19	DR 09.10.19 Screenshots for IPE Dairyland
10/7/19	DR 10.07.19 2019 GNA DDOR DPAG Webinar PG&E 100719
10/8/19	DR 10.08.19 Forecast Shape Exports Peabody 2106 2019-10-08 0155 San Luis Obispo 1108 2019-08 1129 Forecast Shape Exports-Brentwood 2105-2019-10-08 0132 Forecast Shape Exports-Corcoran 1112-2019-10-98 1231 Forecast Shape Exports-FMC 1101-2019-10-08 0103 Forecast Shape Exports-Oceano 1106-2019-10-08 0211
10/9/19	DR 10/09/19 Forecast Shape Export Corcoran 1112 Revised
10/11/19	DR 10/11/19 System Forecast Files Load Growth Data Residential PV Data Residential EV Data Non Residential PV Data
10/11/19	DR 10.11.19 Circuit Forecast Files San Luis Obispo 1108 1019-10-08 1129 Customer Count GRC-WP Table 13-19 Forecast Shape Exports-Brentwood 2105-2019-10-08 0132 Forecast Shape Exports-Corcoran 1112-2019-10-98 1231 Forecast Shape Exports-FMC 1101-2019-10-08 0103 Forecast Shape Exports-Oceano 1106-2019-10-08 0211 Forecast Shape Export Corcoran 1112 Revised
10/16/19	DR 10.16.19 ElectricDistributionResourcesPlanApplication2015 DR CalAdvocates 021-Q05
10/16/19	DR 10.16.19 Project List Canal

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Advice 5688-E
November 15, 2019

Attachment F

IPE DPAG Report
(Confidential Version)

Attachment G

Confidentiality Declaration

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

DECLARATION SUPPORTING CONFIDENTIAL DESIGNATION
ON BEHALF OF
PACIFIC GAS AND ELECTRIC COMPANY (U 39 E)

1. I, Quinn Nakayama, am the Director of Integrated Grid Planning & Innovation at Pacific Gas and Electric Company ("PG&E"), a California corporation. Fong Wan, the Senior Vice President of Energy Policy and Procurement at PG&E, delegated authority to me to sign this declaration. My business office is located at:

Pacific Gas and Electric Company
77 Beale Street
San Francisco, CA 94105

2. PG&E will produce the information identified in paragraph 3 of this Declaration to the California Public Utilities Commission ("CPUC") or departments within or contractors retained by the CPUC in response to a CPUC audit, data request, proceeding, or other CPUC request.

   Name or Docket No. of CPUC Proceeding (if applicable): R.14-08-013 (see D.18-02-004)

3. Title and description of document(s): Advice Letter to Request for Approval to Issue Competitive Solicitations for Distributed Energy Resource (DER) Procurement for Electric Distribution Deferral Opportunities; Attachment B: Candidate DER Distribution Defferal Prioritization Metrics (Confidential); Attachment F: Independent Professional Engineer PG&E 2019 GNA/DDOR Report (Confidential Version).

4. These documents contain confidential information that, based on my information and belief, has not been publicly disclosed. These documents are marked as confidential, and the basis

for confidential treatment and where the confidential information is located on the documents are identified on the following chart.

Check	Basis for Confidential Treatment	Where Confidential Information is located on the documents
x	Customer-specific data, which may include demand, loads, names, addresses, and billing data (Protected under PUC § 8380; Civ. Code §§ 1798 *et seq.*; Govt. Code § 6254; Public Util. Code § 8380; Decisions (D.) 14-05-016, 04-08-055, 06-12-029)	Certain data in Advice Letter to Request for Approval to Issue Competitive Solicitations for Distributed Energy Resource (DER) Procurement for Electric Distribution Deferral Opportunities, Attachment B: Candidate DER Distribution Defferal Prioritization Metrics, and Attachment F: Independent Professional Engineer PG&E 2019 GNA/DDOR Report per CPUC privacy rules adopted in D.14-05-016
	Personal information that identifies or describes an individual (including employees), which may include home address or phone number; SSN, driver's license, or passport numbers; education; financial matters; medical or employment history (not including PG&E job titles); and statements attributed to the individual (Protected under Civ. Code §§ 1798 *et seq.;* Govt. Code § 6254; 42 U.S.C. § 1320d-6; and General Order (G.O.) 77-M)	
	Physical facility, cyber-security sensitive, or critical energy infrastructure data, including without limitation critical energy infrastructure information (CEII) as defined by the regulations of the Federal Energy Regulatory Commission at 18 C.F.R. § 388.113	

	(Protected under Govt. Code § 6254(k), (ab); 6 U.S.C. § 131; 6 CFR § 29.2)	
☐	Proprietary and trade secret information or other intellectual property and protected market sensitive/competitive data (Protected under Civ. Code §§3426 *et seq.*; Govt. Code §§ 6254, *et seq.*, e.g., 6254(e), 6254(k), 6254.15; Govt. Code § 6276.44; Evid. Code §1060; D.11-01-036)	
☐	Corporate financial records (Protected under Govt. Code §§ 6254(k), 6254.15)	
☐	Third-Party information subject to non-disclosure or confidentiality agreements or obligations (Protected under Govt. Code § 6254(k); see, e.g., CPUC D.11-01-036)	
☐	Other categories where disclosure would be against the public interest (Govt. Code § 6255(a))	

5. The importance of maintaining the confidentiality of this information outweighs any public interest in disclosure of this information. This information should be exempt from the public disclosure requirements under the Public Records Act and should be withheld from disclosure.
6. I declare under penalty of perjury that the foregoing is true, correct, and complete to the best of my knowledge.
7. Executed on this 15th day of November, 2019 at San Francisco, California.

Quinn Nakayama
Director, Integrated Grid Planning & Innovation
Pacific Gas and Electric Company

PG&E Gas and Electric
Advice Submittal List
General Order 96-B, Section IV

AT&T
Albion Power Company
Alcantar & Kahl LLP

Alta Power Group, LLC
Anderson & Poole

Atlas ReFuel
BART

Barkovich & Yap, Inc.
P.C. CalCom Solar
California Cotton Ginners & Growers Assn
California Energy Commission
California Public Utilities Commission
California State Association of Counties
Calpine

Cameron-Daniel, P.C.
Casner, Steve
Cenergy Power
Center for Biological Diversity

Chevron Pipeline and Power
City of Palo Alto

City of San Jose
Clean Power Research
Coast Economic Consulting
Commercial Energy
County of Tehama - Department of Public Works
Crossborder Energy
Crown Road Energy, LLC
Davis Wright Tremaine LLP
Day Carter Murphy

Dept of General Services
Don Pickett & Associates, Inc.
Douglass & Liddell

Downey & Brand
East Bay Community Energy
Ellison Schneider & Harris LLP
Energy Management Service
Engineers and Scientists of California
Evaluation + Strategy for Social Innovation
GenOn Energy, Inc.
Goodin, MacBride, Squeri, Schlotz & Ritchie
Green Charge Networks
Green Power Institute
Hanna & Morton
ICF
International Power Technology
Intestate Gas Services, Inc.
Kelly Group
Ken Bohn Consulting
Keyes & Fox LLP
Leviton Manufacturing Co., Inc. Linde
Los Angeles County Integrated Waste Management Task Force
Los Angeles Dept of Water & Power
MRW & Associates
Manatt Phelps Phillips
Marin Energy Authority
McKenzie & Associates

Modesto Irrigation District
Morgan Stanley
NLine Energy, Inc.
NRG Solar

Office of Ratepayer Advocates
OnGrid Solar
Pacific Gas and Electric Company
Peninsula Clean Energy

Pioneer Community Energy
Praxair

Redwood Coast Energy Authority
Regulatory & Cogeneration Service, Inc.
SCD Energy Solutions

SCE
SDG&E and SoCalGas

SPURR
San Francisco Water Power and Sewer
Seattle City Light
Sempra Utilities
Southern California Edison Company
Southern California Gas Company
Spark Energy
Sun Light & Power
Sunshine Design
Tecogen, Inc.
TerraVerde Renewable Partners
Tiger Natural Gas, Inc.

TransCanada
Troutman Sanders LLP
Utility Cost Management
Utility Power Solutions
Utility Specialists

Verizon
Water and Energy Consulting Wellhead Electric Company
Western Manufactured Housing Communities Association (WMA)
Yep Energy