PUBLIC UTILITIES COMMISSION
505 Van Ness Avenue
San Francisco CA 94102-3298

Pacific Gas & Electric Company
ELC (Corp ID 39)
Status of Advice Letter 6403E
As of December 15, 2021

Subject: Request for Approval to Not Issue Competitive Solicitations for Distributed Energy Resource (DER) Procurement for Electric Distribution Deferral Opportunities

Division Assigned: Energy

Date Filed: 11-15-2021

Date to Calendar: 11-17-2021

Authorizing Documents: D1802004

Disposition:	**Accepted**
Effective Date:	**12-15-2021**

Resolution Required: No

Resolution Number: None

Commission Meeting Date: None

CPUC Contact Information:

edtariffunit@cpuc.ca.gov

AL Certificate Contact Information:

Annie Ho
415-973-8794
PGETariffs@pge.com

PUBLIC UTILITIES COMMISSION
505 Van Ness Avenue
San Francisco CA 94102-3298

To: Energy Company Filing Advice Letter

From: Energy Division PAL Coordinator

Subject: Your Advice Letter Filing

The Energy Division of the California Public Utilities Commission has processed your recent Advice Letter (AL) filing and is returning an AL status certificate for your records.

The AL status certificate indicates:

Advice Letter Number
Name of Filer
CPUC Corporate ID number of Filer
Subject of Filing
Date Filed
Disposition of Filing (Accepted, Rejected, Withdrawn, etc.)
Effective Date of Filing
Other Miscellaneous Information (e.g., Resolution, if applicable, etc.)

The Energy Division has made no changes to your copy of the Advice Letter Filing; please review your Advice Letter Filing with the information contained in the AL status certificate, and update your Advice Letter and tariff records accordingly.

All inquiries to the California Public Utilities Commission on the status of your Advice Letter Filing will be answered by Energy Division staff based on the information contained in the Energy Division's PAL database from which the AL status certificate is generated. If you have any questions on this matter please contact the:

Energy Division's Tariff Unit by e-mail to
edtariffunit@cpuc.ca.gov

Pacific Gas and Electric Company®

Sidney Bob Dietz II
Director
Regulatory Relations

Pacific Gas and Electric Company
77 Beale St., Mail Code B13U
P.O. Box 770000
San Francisco, CA 94177

Fax: 415-973-3582

November 15, 2021

Advice 6403-E
(Pacific Gas and Electric Company ID U 39 E)

Public Utilities Commission of the State of California

Subject: **Request for Approval to Not 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 as well as the May 7, 2019 Administrative Law Judge's Ruling Modifying the Distribution Investment Deferral Framework Process (May 2019 ALJ Ruling) and the June 21, 2021 Administrative Law Judge's Ruling Modifying the Distribution Investment Deferral Framework—Filing And Process Requirements (May 2021 ALJ Ruling)[1] in Rulemaking (R.) 14-08-013, 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 not issue competitive solicitations to procure distributed energy resource (DER) solutions for identified electric distribution deferral opportunities as described below.

1. Background

On August 14, 2014, the Commission instituted R.14-08-013 to establish policies, procedures, and rules to guide the California investor-owned utilities (IOUs) in developing their Distribution Resources Plan (DRP) 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 DRP proposals to the Commission. The Commission organized the review of the DRP filing content into three

[1] May 11, 2020 Administrative Law Judge's Ruling Modifying the Distribution Investment Deferral Framework—Filing and Process Requirements, Attachment A, pp. 89-98. Attachment A was subsequently revised on June 12, 2020

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, the May 2019 ALJ Ruling modified the Distribution Investment Deferral Framework (DIDF). One notable modification was the new August submission date for both the GNA and DDOR reports.

There were two improvement rulings modifying the DIDF process by Administrative Law Judge (ALJ) Mason in 2020. The April 13, 2020 Administrative Law Judge’s Ruling Modifying the Distribution Investment Deferral Framework Process (April 2020 ALJ Ruling) updated the Independent Professional Engineer (IPE) scope of work for the DIDF process and provided the 2020-2021 DIDF cycle schedule. The May 2020 ALJ Ruling further modifies the DIDF process and filings requirements by focusing on the comments and reforms related to aspects of the DIDF.

In June 2021, the assigned ALJ issued a ruling on recommended reforms to the DIDF process and addressed alignment with requirements adopted by Decision D. 21-02-006. Specifically, the ruling introduced eight new reforms and amended eight reforms. As a result of this ruling, the Partnership and Standard Offer Contract (SOC) Pilots will align within the current DIDF process and are subject to DIDF reforms while pilots are active.

PG&E jointly filed its fourth GNA and DDOR on August 16, 2021 and provided it to its Distribution Planning Advisory Group (DPAG). Also, as required by D.18-02-004, PG&E initiated DPAG meetings on September 20, 2021 and October 22, 2021 to receive advisory input on candidate distribution deferral opportunities that were selected through various sourcing mechanisms. PG&E also retained an IPE to attend the meetings and prepare a DPAG Report.

The Decision also addresses certain reforms to the DIDF Request for Offer (RFO) process. OP 11 revised Reform No. 40, and directs PG&E to request approval to not include in the DIDF RFO process any remaining candidate deferral opportunities or other planned investments identified in the Grid Needs Assessment (GNA) and (Distribution Deferral Opportunity Report (DDOR) filings or by DPAG stakeholders or Energy Division. Alternatively, if any additional Tier One opportunities are identified during the DPAG, PG&E must request approval to launch a second round of RFOs. In this Advice Letter, PG&E is asking for approval for no additional RFO for distribution deferral projects in compliance with Revised Reform No. 40 in the June 2021 ALJ Ruling.

2. Overview of the Distribution Investment Deferral Framework Process

Pursuant to the DIDF as specified in D.18-02-004, the May 2019 ALJ Ruling, the May 2020 ALJ Ruling and the June 21, 2021 ALJ Ruling, PG&E has completed the following:

- August 16, 2021: Submitted PG&E's 2021 GNA Report
- August 16, 2021: Submitted PG&E's 2021 DDOR
- September 20, 2021: Hosted PG&E's DPAG Meeting #1 via Webinar
- October 15, 2021: Submitted Supplement to PG&E's 2021 Line Section GNA and DDOR
- October 22, 2021: Hosted PG&E's DPAG Meeting #2 via Webinar
- October 28, 2021: Submitted Corrected Supplement to PG&E's 2021 Line Section GNA and DDOR

3. Proposal to Not Solicit Candidate DER Distribution Deferral Projects

PG&E is requesting approval to not solicit additional DER distribution deferral projects for the Fall 2021 DIDF RFO. PG&E does not recommend pursuing competitive solicitations of DER for additional projects currently due to their low likelihood of achieving a successful outcome. Moreover, focusing developer efforts on only the 13 selected projects may improve their probability of success.[2] The other Tier 2 and Tier 3 Candidate Deferral Opportunities include characteristics that decrease their likelihood of success, thus are not recommended for solicitation.

4. Prioritization Metrics

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

The May 11, 2020 ALJ Ruling[3] modified several elements of the Distribution Investment Deferral Framework Process, including changes to the Prioritization Metrics Workbook. A Joint Prioritization Metrics Workbook Template (JPMWT) was developed jointly by the IOUs and was approved by Energy Division on May 18, 2021. The JPMWT consists of a total of nine sub-metrics – five quantitative sub-metrics, which are normalized and

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[2] In the August 30, 2021 Independent Evaluation Report For Pacific Gas & Electric's 2021 Distribution Investment Deferral Framework Request For Offers, the Individual Evaluator (IE) considers that while providing many opportunities may develop a wide array of offers, it may have a negative effect in providing too many options, diffusing the bidding community's attention, and decreasing the likelihood of Participants submitting enough offers at any one location to meet the location's needs.

[3] May 11, 2020 Administrative Law Judge's Ruling Modifying the Distribution Investment Deferral Framework, Attachment A (subsequently revised on June 12, 2020), — Prioritization Metrics, DIDF Reform #20. pp.92.

summed to create an overall score, and four sub-metrics used to flag candidate deferral opportunities that are unlikely to be successful for DER sourcing.
For ease of summarizing prioritization metric results, each tier represents the JPMWT proposed priority ranking of candidate deferral projects based on likelihood of success for DER sourcing. The JPMWT has a 3-tier system, where each tier represents the proposed priority ranking of those candidate deferral projects likelihood of success for DER sourcing. The following table (Table 1) summarizes the JPMWT 3-tier system.

Table 1: Joint Prioritization Metrics Workbook Template 3-Tier Prioritization System

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

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.[4] 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 2021 DDOR. The prioritization metrics and tiering were then thoroughly discussed throughout the DPAG process. The prioritization metrics for each candidate deferral opportunity are included in Attachment A.

The Public Advocate's Office (PAO) submitted questions after the September 20 DPAG meeting to PG&E regarding the prioritization process. The question addressed to PG&E was regarding the rationale for the relative ranking-based approach for selecting candidate deferral projects. In accordance with the May 11, 2020 ALJ Ruling[5], the JPMWT was based on SCE's 2019 prioritization metrics workbook, which used a ranking-based approach. The JPMWT uses a hybrid approach that ranks projects relative to each other and incorporates lessons-learned from previous deferrals. PG&E is open to considering the suggested method of ranking based on absolute thresholds in future DIDF cycles. However, further discussion would be required to evaluate appropriate thresholds to set for the other four sub-metrics that currently do not use absolute thresholds (i.e.,

[4] For example, green 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.
[5] May 11, 2020 Administrative Law Judge's Ruling Modifying the Distribution Investment Deferral Framework, Attachment A (subsequently revised on June 12, 2020), — Prioritization Metrics, DIDF Reform #19. pp.92.

LNBA). PG&E recommends that revision to the prioritization process be taken up via the annual DIDF Improvements process.

The PAO also submitted a question to the IPE that requested them to "validate and verify projects that were relegated to Tier 3 projects due to flagging but ranked relatively highly on prioritization metrics." Since the quantitative score used to rank projects utilizes only five of the nine sub-metrics, PG&E does not support using only some of the sub-metrics in the approved JPMWT at this time. As mentioned above, PG&E would consider the possibility of converting the four sub-metrics used for flags into quantitative scores for future DIDF cycles. PG&E recommends that revision to the prioritization process be taken up via the annual DIDF Improvements process.

5. Candidate Deferral Opportunities

5.1.1. Candidate Deferral Opportunities Recommended for Solicitation

PG&E is pursuing competitive solicitations for the Candidate Deferral Opportunities listed in Table 2. Additional details are provided on the respective websites for the Fall 2021 DIDF RFO, 2021 DIDF SOC Pilot, and DIDF Partnership Pilot.

Table 2: Candidate Deferral Opportunities Recommended for Solicitation

Tier	Candidate Deferral	In-Service Date	Deficiency (MW)	Sourcing Mechanism
Tier 1	Coalinga No 1 Bank 2	5/1/2024	[redacted]	Partnership Pilot
Tier 1	Embarcadero (SF Z) 1116	4/1/2026	0.3	Partnership Pilot
Tier 1	Embarcadero (SF Z) 1118	6/1/2025	1.3	Partnership Pilot
Tier 1	French Camp Bank 1	5/1/2024	[redacted]	DIDF RFO
Tier 1	Lakeview 1110	5/1/2024	[redacted]	DIDF RFO
Tier 1	Mormon Bank 2	6/1/2025	1.1	DIDF RFO
Tier 1	Newhall Bank 3	6/1/2024	[redacted]	DIDF RFO
Tier 1	Ripon 1705	5/1/2024	5.9	DIDF RFO
Tier 1	Rocklin 1105	5/1/2025	0.7	Partnership Pilot
Tier 1	Saratoga 1102	5/1/2026	[redacted]	DIDF RFO
Tier 1	Vierra Bank 3	5/1/2024	[redacted]	SOC Pilot
Tier 2	Anita 1105	6/1/2024	3.8	Partnership Pilot
Tier 2	Belle Haven Bank 4	5/1/2024	3.9	Partnership Pilot

5.1.2. Candidate Deferral Opportunities Not Recommended for Solicitation

PG&E does not recommend pursuing competitive solicitations for the Tier 2 and Tier 3 candidate deferral opportunities listed in Table 3.

Table 3: Candidate Deferral Opportunities Not Recommended for Solicitation

Tier	Candidate Deferral	In-Service Date	Deficiency (MW)	Sourcing Mechanism
Tier 2	Blackwell Bank 1	6/1/2025	[redacted]	Not Recommended
Tier 2	Bonita Bank 2	5/1/2024	[redacted]	Not Recommended
Tier 2	Gabilan Bank 2	5/1/2024	[redacted]	Not Recommended
Tier 2	Green Valley Bank 3	5/1/2024	6.2	Not Recommended
Tier 2	Hammonds Bank 1	5/1/2024	[redacted]	Not Recommended
Tier 2	Plainfield Bank 1	6/1/2024	4.7	Not Recommended
Tier 2	San Miguel Bank 2	6/1/2024	[redacted]	Not Recommended
Tier 3	Airways Bank 3	5/1/2024	4.5	Not Recommended
Tier 3	Ames 1103	6/1/2025	[redacted]	Not Recommended
Tier 3	Arbuckle Bank 2	4/1/2024	2.1	Not Recommended
Tier 3	Banta Bank 1	5/1/2024	[redacted]	Not Recommended
Tier 3	Chualar Bank 1	5/1/2024	[redacted]	Not Recommended
Tier 3	Edenvale 2108	1/1/2024	2.0	Not Recommended
Tier 3	Extend Edenvale 2111 to 2112	4/2/2024	[redacted]	Not Recommended
Tier 3	Fulton Bank 5	5/1/2025	4.8	Not Recommended
Tier 3	Garberville Bank 2	6/1/2024	11.3	Not Recommended
Tier 3	Giffen Bank 2	4/1/2024	[redacted]	Not Recommended
Tier 3	Lockeford Bank 1	5/1/2025	19.5	Not Recommended
Tier 3	Martin (SF H) 1107	1/1/2024	1.1	Not Recommended
Tier 3	Martin (SF H) 1108	1/1/2024	[redacted]	Not Recommended
Tier 3	Mc Kee 1102	6/1/2024	6.3	Not Recommended
Tier 3	Molino Bank 1	6/1/2025	0.8	Not Recommended
Tier 3	Montague Bank 2	5/1/2025	7.6	Not Recommended
Tier 3	Oceano 1106	1/1/2024	1.1	Not Recommended
Tier 3	Rincon Bank 1	5/1/2024	6.1	Not Recommended
Tier 3	Rob Roy 2105	1/1/2024	4.6	Not Recommended
Tier 3	Salinas 1102	1/1/2024	[redacted]	Not Recommended
Tier 3	Spence Bank 2	5/1/2024	[redacted]	Not Recommended
Tier 3	Storey 1103	5/1/2024	4.3	Not Recommended
Tier 3	Willow Pass Bank 1	6/1/2024	10.2	Not Recommended
Tier 3	Wolfe 1111 & Wolfe 1112	6/1/2024	[redacted]	Not Recommended

Tier 2 Candidate Deferral Opportunities Not Recommended for Solicitation:

Tier 2 Candidate Deferral Opportunities scored in the middle (2nd and 3rd quartile) in relation to all other Candidate Deferrals and include characteristics that indicate they are unlikely to be successfully deferred now. PG&E recommends not pursuing these Candidate Deferral Opportunities currently.

Table 4: Tier 2 Candidate Deferral Opportunities Not Recommended for Solicitation

Tier	DDOR ID	Candidate Deferral	In-Service Date	Deficiency (MW)	Cost Effectiveness	Forecast Certainty	Market Assessment
2	DDOR109	Blackwell Bank 1	6/1/2025	[redacted]	0	0	0
	DDOR089	Bonita Bank 2	5/1/2024	[redacted]	0	0	0
	DDOR079	Gabilan Bank 2	5/1/2024	[redacted]	0	0	0
	DDOR080	Green Valley Bank 3	5/1/2024	6.2	0	0	0
	DDOR088	Hammonds Bank 1	5/1/2024	[redacted]	0	0	0
	DDOR097	Plainfield Bank 1	6/1/2024	4.7	0	0	0
	DDOR092	San Miguel Bank 2	6/1/2024	[redacted]	0	0	0

The Bonita Bank 2 candidate deferral was identified by the Independent Professional Engineer (IPE) for further discussion during the October DPAG webinar. PG&E does not recommend this opportunity for RFO as follows:

- Bonita Bank 2 – The grid need certainty score for this candidate deferral is negatively impacted by a large load application in the area, indicating volatility in the forecasted need. The operational requirement is a flat, baseload profile that can be called at any time of day, potentially making energy storage a difficult option. This candidate deferral opportunity has more than one grid need location which introduces additional complexity and potential interconnection costs, which reduces the likelihood of successfully deferring the project since all three grid needs (located on Bonita Bank 1, Bonita 1102, and Storey 1106) would need to be addressed.

Tier 3 Candidate Deferral Opportunities:

PG&E does not recommend pursuing competitive solicitations for Tier 3 candidate deferral opportunities. The Tier 3 projects have one or more flagged attributes that have been identified and/or achieved a negative Red-Amber-Green (RAG) score, which indicate that it is unlikely a DER deferral solution can successfully be sourced.

Table 5: Tier 3 Prioritization Metrics Tiering Summary

Tier	DDOR ID	Candidate Deferral	In-Service Date	Deficiency (MW)	Cost Effectiveness	Forecast Certainty	Market Assessment
3	DDOR081	Airways Bank 3	5/1/2024	4.5	0	0	FLAG
	DDOR108	Ames 1103	6/1/2025	[redacted]	-1	0	0
	DDOR076	Arbuckle Bank 2	4/1/2024	2.1	0	-1	0
	DDOR113	Banta Bank 1	5/1/2024	[redacted]	-1	-1	-1
	DDOR091	Chualar Bank 1	5/1/2024	[redacted]	-1	0	-1
	DDOR131	Edenvale 2108	10/1/2024	2.0	FLAG	1	FLAG
	DDOR118	Extend Edenvale 2111 to 2112	4/2/2024	[redacted]	FLAG	1	-1
	DDOR104	Fulton Bank 5	5/1/2025	4.8	0	-1	FLAG
	DDOR094	Garberville Bank 2	6/1/2024	11.3	1	-1	-1
	DDOR075	Giffen Bank 2	4/1/2024	[redacted]	0	0	-1
	DDOR105	Lockeford Bank 1	5/1/2025	19.5	0	-1	FLAG
	DDOR129	Martin (SF H) 1107	10/1/2024	1.1	FLAG	1	FLAG
	DDOR130	Martin (SF H) 1108	10/1/2024	[redacted]	FLAG	1	FLAG
	DDOR098	Mc Kee 1102	6/1/2024	6.3	0	1	FLAG
	DDOR106	Molino Bank 1	6/1/2025	0.8	FLAG	-1	1
	DDOR102	Montague Bank 2	5/1/2025	7.6	0	0	FLAG
	DDOR128	Oceano 1106	10/1/2024	1.1	FLAG	1	FLAG
	DDOR103	Rincon Bank 1	5/1/2024	6.1	0	-1	0
	DDOR126	Rob Roy 2105	10/1/2024	4.6	FLAG	1	FLAG
	DDOR127	Salinas 1102	10/1/2024	[redacted]	FLAG	1	FLAG
	DDOR078	Spence Bank 2	5/1/2024	[redacted]	-1	-1	FLAG
	DDOR077	Storey 1103	5/1/2024	4.3	0	0	FLAG
	DDOR093	Willow Pass Bank 1	6/1/2024	10.2	0	-1	-1
	DDOR096	Wolfe 1111 & Wolfe 1112	6/1/2024	[redacted]	-1	0	FLAG

The Airways Bank 3 and Mc Kee 1102 candidate deferrals were identified by the Independent Professional Engineer (IPE) for discussion during the October DPAG webinar. PG&E does not recommend these opportunities for RFO as follows:

- Airways Bank 3 – This candidate deferral opportunity has more than one grid need location (a total of five grid needs located on Airways 1107, Airways Bank 2, Airways 1102, Coppermine 1104, and Airways 1107). This introduces additional complexity and potential interconnection costs, which reduces the likelihood of successfully deferring the project since all five grid needs would need to be addressed. A project with more than three grid need locations receives a flag under the Market Assessment, indicating an even lower likelihood to be successfully sourced for solicitation. In addition to the capacity needs, Airways Bank 3 has a voltage need that would result in further complexity in service requirements. The approved JPMWT was not designed to evaluate voltage needs, so the voltage need further diminishes the likelihood for successful solicitation than what is reflected in the Tiering process.

- Mc Kee 1102 – This candidate deferral opportunity has more than one grid need location (a total of four grid needs located on Mc Kee Bank 1, Mc Kee 1110, Mc Kee 1108, and Mc Kee 1107). This introduces additional complexity and potential interconnection costs, which reduces the likelihood of successfully deferring the project since all four needs would need to be addressed. A project with more than three grid need locations receives a flag under the Market Assessment metric, indicating an even lower likelihood to be successfully sourced for solicitation.

5.1.3. Cancelled Candidate Deferral Opportunity

- Zamora 1108 – The initial deferral opportunity included in PG&E's DDOR addressed two capacity grid needs (Knights Landing Bank 1 and Zamora Bank 1) and had an expected in-service date of May 1, 2024. An equipment failure triggered an emergency project to replace Knights Landing Bank 1 and the station regulator. With this emergency bank replacement, Knights Landing Bank 1 is no longer a capacity need and the Zamora Bank 1 capacity need is expected to be solved with a load transfer. The emergency project fails both the technical screen and the timing screen as the in-service date is in 2022. The initial Zamora 1108 project is tentatively cancelled for the current cycle pending further evaluation upon completion of the Knights Landing Bank 1 emergency project.

6. Commission Action Requested

For the reasons stated herein, PG&E respectfully requests approval for no additional candidate deferrals or planned investments for the Fall 2021 DIDF RFO.

Tariff Revisions

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

Protests

*****Due to the COVID-19 pandemic and the shelter at home orders, PG&E is currently unable to receive protests or comments to this advice letter via U.S. mail or fax. Please submit protests or comments to this advice letter to EDTariffUnit@cpuc.ca.gov and PGETariffs@pge.com*****

Anyone wishing to protest this filing may do so by letter sent via U.S. mail, facsimile or E-mail, no later than December 6, 2021, which is 21 days[6] after the date of this submittal. Protests must be submitted to:

[6] The 20-day protest period concludes on a weekend, therefore, PG&E is moving this date to the following business day.

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:

Sidney Bob Dietz II
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

Pursuant to General Order (GO) 96-B, Rule 5.2, this advice letter is submitted with a Tier 2 designation. PG&E requests that this **Tier 2** advice submittal become effective on regular notice, December 15, 2021**,** which is 30 calendar days after the date of submittal.

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 filings can also be accessed electronically at: http://www.pge.com/tariffs/.

/S/

Sidney Bob Dietz II
Director, Regulatory Relations

Attachments

Attachment A – Candidate Deferral Prioritization Metrics Summary (Public)
Attachment B – Candidate Deferral Prioritization Metrics Full (Public)
Attachment C – IPE DPAG Report (Public)

cc: Service Lists R.14-08-013 and R.14-10-003
Gabe Petlin – Energy Division
Robert Peterson – Energy Division

California Public Utilities Commission

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 U39 E)

Utility type:
☑ ELC ☐ GAS ☐ WATER
☐ PLC ☐ HEAT

Contact Person: Annie Ho
Phone #: (415) 973-8794
E-mail: PGETariffs@pge.com
E-mail Disposition Notice to: AMHP@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) #: 6403-E

Tier Designation: 2

Subject of AL: Request for Approval to Not Issue Competitive Solicitations for Distributed Energy Resource (DER) Procurement for Electric Distribution Deferral Opportunities

Keywords (choose from CPUC listing): Compilance

AL Type: ☐ Monthly ☐ Quarterly ☐ 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? ☑ Yes ☐ No

If yes, specification of confidential information: See Confidentiality Declaration & Matrix
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

Resolution required? ☐ Yes ☑ No

Requested effective date: 12/15/21

No. of tariff sheets: N/A

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: Sidney Bob Dietz II, 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 6403-E
November 15, 2021

Confidentiality Declaration & Matrix

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

   Pacific Gas and Electric Company
   77 Beale Street, Mail Code B13U
   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

3. Title and description of document(s): DIDF Non-Solicitation Advice Letter; Attachment A; Attachment B; IPE DPAG Report

4. These documents contain confidential information that, based on my information and belief, has not been publicly disclosed. These documents have been 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)	Grey-shaded information in Advice Letter 6403-E; Attachment A, Attachment B, and IPE DPAG Report
☐	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 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 and/or General Order 66-D ("The subject information: (1) is not customarily in the public domain by providing a declaration in compliance with Section 3.2(c) stating that the subject information is not related to the location of a physical structure that is visible with the naked eye or is available publicly online or in print; **and** (2) the subject information either: could allow a bad actor to attack, compromise or incapacitate physically or electronically a facility providing critical utility service; or discusses vulnerabilities of a facility providing critical utility service"). (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)) [NEED TO EXPLAIN HOW THE PUBLIC INTEREST SERVED BY NOT DISCLOSING THE RECORD CLEARLY OUTWEIGHS THE PUBLIC INTEREST SERVED BY DISCLOSURE]): ____________________________	

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, 2021 at San Francisco, California.

/S/

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

PACIFIC GAS AND ELECTRIC COMPANY (U 39 E)

R.14-08-013
ATTACHMENT TO DECLARATION
11/15/2021

ATTACHMENT NAME	DOCUMENT NAME	CATEGORY OF CONFIDENTIALITY	LOCATION
Advice Letter 6403-E.	Advice Letter requesting approval to not include in the DIDF RFO process any remaining candidate deferral opportunities or other planned investments	Customer-specific data	Marked as "Customer Confidential" or "CC" in the Advice Letter 6403-E and Attachment A

PACIFIC GAS AND ELECTRIC COMPANY

Attachment A

Candidate DER Distribution Deferral Prioritization Metrics

(Public Version)

Attachment A - Candidate DER Distribution Deferral Prioritization Metrics

Table 1: Candidate Distribution Deferral Prioritization Metrics

Tier	DDOR ID	Candidate Deferral	In-Service Date	Deficiency (MW)	Cost Effectiveness	Forecast Certainty	Market Assessment
Tier 1	DDOR082	Coalinga No 1 Bank 2	05/01/2024	[redacted]	1	-1	1
Tier 1	DDOR111	Embarcadero (SF Z) 1116	04/01/2026	0.3	1	0	1
Tier 1	DDOR110	Embarcadero (SF Z) 1118	06/01/2025	1.3	0	1	0
Tier 1	DDOR086	French Camp Bank 1	05/01/2024	[redacted]	1	0	0
Tier 1	DDOR090	Lakeview 1110	05/01/2024	[redacted]	1	0	1
Tier 1	DDOR115	Mormon Bank 2	06/01/2025	1.1	1	0	1
Tier 1	DDOR095	Newhall Bank 3	06/01/2024	[redacted]	1	0	1
Tier 1	DDOR085	Ripon 1705	05/01/2024	5.9	0	1	0
Tier 1	DDOR101	Rocklin 1105	05/01/2025	0.7	1	-1	1
Tier 1	DDOR112	Saratoga 1102	05/01/2026	[redacted]	1	0	1
Tier 1	DDOR087	Vierra Bank 3	05/01/2024	[redacted]	1	0	1
Tier 2	DDOR100	Anita 1105	06/01/2024	3.8	0	0	0
Tier 2	DDOR083	Belle Haven Bank 4	05/01/2024	3.9	0	0	0
Tier 2	DDOR109	Blackwell Bank 1	06/01/2025	[redacted]	0	0	0
Tier 2	DDOR089	Bonita Bank 2	05/01/2024	[redacted]	0	0	0
Tier 2	DDOR079	Gabilan Bank 2	05/01/2024	[redacted]	0	0	0
Tier 2	DDOR080	Green Valley Bank 3	05/01/2024	6.2	0	0	0
Tier 2	DDOR088	Hammonds Bank 1	05/01/2024	[redacted]	0	0	0
Tier 2	DDOR097	Plainfield Bank 1	06/01/2024	4.7	0	0	0
Tier 2	DDOR092	San Miguel Bank 2	06/01/2024	[redacted]	0	0	0
Tier 3	DDOR081	Airways Bank 3	05/01/2024	4.5	0	0	FLAG
Tier 3	DDOR108	Ames 1103	06/01/2025	[redacted]	-1	0	0
Tier 3	DDOR076	Arbuckle Bank 2	04/01/2024	2.1	0	-1	0
Tier 3	DDOR113	Banta Bank 1	05/01/2024	[redacted]	-1	-1	-1
Tier 3	DDOR091	Chualar Bank 1	05/01/2024	[redacted]	-1	0	-1
Tier 3	DDOR131	Edenvale 2108	10/01/2024	2.0	FLAG	1	FLAG
Tier 3	DDOR118	Extend Edenvale 2111 to 2112	04/02/2024	[redacted]	FLAG	1	-1
Tier 3	DDOR104	Fulton Bank 5	05/01/2025	4.8	0	-1	FLAG
Tier 3	DDOR094	Garberville Bank 2	06/01/2024	11.3	1	-1	-1
Tier 3	DDOR075	Giffen Bank 2	04/01/2024	[redacted]	0	0	-1
Tier 3	DDOR105	Lockeford Bank 1	05/01/2025	19.5	0	-1	FLAG
Tier 3	DDOR129	Martin (SF H) 1107	10/01/2024	1.1	FLAG	1	FLAG
Tier 3	DDOR130	Martin (SF H) 1108	10/01/2024	[redacted]	FLAG	1	FLAG
Tier 3	DDOR098	Mc Kee 1102	06/01/2024	6.3	0	1	FLAG
Tier 3	DDOR106	Molino Bank 1	06/01/2025	0.8	FLAG	-1	1
Tier 3	DDOR102	Montague Bank 2	05/01/2025	7.6	0	0	FLAG
Tier 3	DDOR128	Oceano 1106	10/01/2024	1.1	FLAG	1	FLAG
Tier 3	DDOR103	Rincon Bank 1	05/01/2024	6.1	0	-1	0
Tier 3	DDOR126	Rob Roy 2105	10/01/2024	4.6	FLAG	1	FLAG
Tier 3	DDOR127	Salinas 1102	10/01/2024	[redacted]	FLAG	1	FLAG
Tier 3	DDOR078	Spence Bank 2	05/01/2024	[redacted]	-1	-1	FLAG
Tier 3	DDOR077	Storey 1103	05/01/2024	4.3	0	0	FLAG
Tier 3	DDOR093	Willow Pass Bank 1	06/01/2024	10.2	0	-1	-1
Tier 3	DDOR096	Wolfe 1111 & Wolfe 1112	06/01/2024	[redacted]	-1	0	FLAG

Advice 6403-E
November 15, 2021

Attachment B

Candidate Deferral Prioritization Metrics Full

(Public)

Prioritization Metrics Template

Template Inputs

	Cost Effectiveness			Forecast Certainty		Market Assessment			
	LNBA ($/MW-yr)	LNBA ($/MWh-yr)	Unit Cost of Traditional Mitigation ($)	Grid Need Certainty	Year of Need	Duration (Hours)	Capacity Need (MW)/Circuit	Operational Requirement	Number of Grid Needs
DIDF Baseline Year					2021				
Max value for normalization	1.07	7,508		-12		48	8.1		
Min value for normalization	0.01	2		-40		2	0.2		
Flag threshold			1,000,000		4			RT DA + RT	3
Top quartile threshold	11.5			11.5		11.5			
Bottom quartile threshold	34.5			33.5		34.5			

Metrics Legend	RAG Score	
Red Value	-1	
Amber Value	0	
Green Value	1	
Tier 1	Less Than	0
Tier 2	Equal To	0
Tier 3	Greater Than	0

Raw Data

Project ID	Project Description	LNBA ($/MW-yr)	LNBA ($/MWh-yr)	LNBA ($/MWh-day) (Info only)	Unit Cost of Traditional Mitigation ($)	Grid Need Certainty	Operating Date (Info Only)	Year of Need	Year of Need Indicator	Duration (Hours)	Capacity Need (MW)	Circuits	Capacity Need (MW)/Circuit	Operational Requirement	Number of Grid Needs
DDOR081	Airways Bank 3	0.18	522	337,038	11,900,000	-19	5/1/2024	2021	0	24	4.5	7	0.6	DA	5
DDOR108	Ames 1103	0.02	14	12,230	2,400,000	-20	6/1/2025	2025	4	[redacted]	[redacted]	6	[redacted]	DA	3
DDOR100	Anita 1105	0.08	177	95,720	2,500,000	-27	6/1/2024	2021	0	7	3.8	6	0.6	DA	3
DDOR076	Arbuckle Bank 2	0.24	254	261,568	9,570,000	-30	4/1/2024	2021	0	7	2.1	2	1.1	DA	2
DDOR113	Banta Bank 1	0.03	5	11,377	10,354,000	-29	5/1/2024	2022	1	[redacted]	[redacted]	5	[redacted]	DA	2
DDOR083	Belle Haven Bank 4	0.20	103	117,155	14,700,000	-25	5/1/2024	2021	0	12	3.9	2	2.0	DA	1
DDOR109	Blackwell Bank 1	0.12	59	69,767	6,489,000	-23	6/1/2025	2021	0	[redacted]	[redacted]	2	[redacted]	DA	1
DDOR089	Bonita Bank 2	0.19	186	150,576	11,900,000	-21	5/1/2024	2021	0	[redacted]	[redacted]	5	[redacted]	DA	3
DDOR091	Chualar Bank 1	0.02	9	21,030	6,500,000	-25	5/1/2024	2021	0	[redacted]	[redacted]	3	[redacted]	DA	2
DDOR082	Coalinga No 1 Bank 2	0.70	2,688	1,223,155	6,500,000	-33	5/1/2024	2024	3	[redacted]	[redacted]	2	[redacted]	DA	1
DDOR131	Edenvale 2108	0.01	116	1,631	95,000	-15	10/1/2024	2021	0	24	2.0	1	2.0	RT	1
DDOR111	Embarcadero (SF Z) 1116	0.45	4,251	446,355	2,501,000	-19	4/1/2026	2024	3	5	0.3	1	0.3	DA	1
DDOR110	Embarcadero (SF Z) 1118	0.10	43	67,339	2,501,000	-17	6/1/2025	2025	4	9	1.3	1	1.3	DA	1
DDOR118	Extend Edenvale 2111 to 2112	0.01	2	3,495	945,000	-15	4/2/2024	2024	3	[redacted]	[redacted]	1	[redacted]	DA	1
DDOR086	French Camp Bank 1	0.24	346	213,410	6,500,000	-27	5/1/2024	2022	1	[redacted]	[redacted]	2	[redacted]	DA	1
DDOR104	Fulton Bank 5	0.07	352	98,490	6,500,000	-36	5/1/2025	2021	0	6	4.8	8	0.6	DA	4
DDOR079	Gabilan Bank 2	0.05	22	54,495	6,500,000	-22	5/1/2024	2021	0	[redacted]	[redacted]	3	[redacted]	DA	2
DDOR094	Garberville Bank 2	0.33	48	121,816	53,907,000	-37	6/1/2024	2021	0	24	11.3	4	2.8	DA	3
DDOR075	Giffen Bank 2	0.06	11	17,993	11,900,000	-24	4/1/2024	2021	0	[redacted]	[redacted]	3	[redacted]	DA	2
DDOR080	Green Valley Bank 3	0.06	21	30,343	6,500,000	-27	5/1/2024	2021	0	13	6.2	2	3.1	DA	1
DDOR088	Hammonds Bank 1	0.04	33	23,357	6,500,000	-25	5/1/2024	2022	1	[redacted]	[redacted]	4	[redacted]	DA	2
DDOR090	Lakeview 1110	0.54	1,876	1,247,479	4,496,000	-21	5/1/2024	2024	3	[redacted]	[redacted]	1	[redacted]	DA	1
DDOR105	Lockeford Bank 1	0.04	74	6,146	10,885,000	-29	5/1/2025	2021	0	48	19.5	6	3.2	DA + RT	3
DDOR129	Martin (SF H) 1107	0.01	159	2,227	150,000	-15	10/1/2024	2021	0	24	1.1	1	1.1	RT	1
DDOR130	Martin (SF H) 1108	0.01	191	2,672	180,000	-15	10/1/2024	2021	0	[redacted]	[redacted]	1	[redacted]	RT	1
DDOR098	Mc Kee 1102	0.04	93	54,010	2,450,000	-15	6/1/2024	2021	0	7	6.3	6	1.1	DA	4
DDOR106	Molino Bank 1	0.03	47	53,188	400,000	-33	6/1/2025	2023	2	3	0.8	4	0.2	DA	2
DDOR102	Montague Bank 2	0.05	22	24,578	6,500,000	-25	5/1/2025	2021	0	11	7.6	3	2.5	RT	1
DDOR115	Mormon Bank 2	1.07	7,508	1,877,885	16,680,000	-22	6/1/2025	2021	0	4	1.1	3	0.4	DA	2
DDOR095	Newhall Bank 3	0.22	1,708	613,616	6,500,000	-22	6/1/2024	2021	0	[redacted]	[redacted]	2	[redacted]	DA	2
DDOR128	Oceano 1106	0.02	459	6,428	425,000	-15	10/1/2024	2021	0	24	1.1	1	1.1	RT	1
DDOR097	Plainfield Bank 1	0.14	158	135,163	11,940,000	-25	6/1/2024	2021	0	7	4.7	1	4.7	DA	1
DDOR103	Rincon Bank 1	0.12	75	96,355	6,500,000	-40	5/1/2024	2021	0	9	6.1	2	3.0	DA	1
DDOR085	Ripon 1705	0.04	66	50,775	1,900,000	-16	5/1/2024	2021	0	7	5.9	5	1.2	DA	3
DDOR126	Rob Roy 2105	0.01	133	3,721	500,000	-13	10/1/2024	2021	0	24	4.6	1	4.6	RT	1
DDOR101	Rocklin 1105	0.10	1,333	311,947	1,400,000	-28	5/1/2025	2022	1	2	0.7	2	0.4	DA	1
DDOR127	Salinas 1102	0.01	228	3,186	250,000	-12	10/1/2024	2021	0	[redacted]	[redacted]	1	[redacted]	RT	1
DDOR092	San Miguel Bank 2	0.22	223	185,831	9,366,000	-23	6/1/2024	2021	0	[redacted]	[redacted]	5	[redacted]	DA	2
DDOR112	Saratoga 1102	0.52	1,427	649,211	5,092,000	-19	5/1/2026	2021	0	[redacted]	[redacted]	1	[redacted]	DA	1
DDOR078	Spence Bank 2	0.02	5	11,548	9,967,000	-31	5/1/2024	2021	0	[redacted]	[redacted]	6	[redacted]	DA	4
DDOR077	Storey 1103	0.03	60	38,264	2,400,000	-20	5/1/2024	2021	0	24	4.3	4	1.1	DA	4
DDOR087	Vierra Bank 3	0.64	2,255	1,120,871	11,900,000	-25	5/1/2024	2021	0	[redacted]	[redacted]	2	[redacted]	DA	1
DDOR093	Willow Pass Bank 1	0.07	49	41,852	12,498,000	-29	6/1/2024	2021	0	11	10.2	2	5.1	DA	1
DDOR096	Wolfe 1111 & Wolfe 1112	0.02	4	7,849	8,788,000	-19	6/1/2024	2021	0	[redacted]	[redacted]	13	[redacted]	DA	7
DDOR084	Zamora 1108	0.20	1,594	653,758	1,900,000	-16	5/1/2024	2021	0	3	1.1	4	0.3	DA	2

Project ID	Step 1: Normalize Raw Data									Step 2: Apply Flags								
	LNBA ($/MW-yr)	LNBA ($/MWh-yr)	Unit Cost of Traditional Mitigation ($)	Grid Need Certainty	Year of Need	Duration (Hours)	Capacity Need (MW)/Circuit	Operational Requirement	Number of Grid Needs	LNBA ($/MW-yr)	LNBA ($/MWh-yr)	Unit Cost of Traditional Mitigation ($)	Grid Need Certainty	Year of Need	Duration (Hours)	Capacity Need (MW)/Circuit	Operational Requirement	Number of Grid Needs
DDOR081	0.17	0.07		0.75		0.52	0.94											FLAG
DDOR108	0.01	0.00		0.71		[redacted]	[redacted]											
DDOR100	0.07	0.02		0.46		0.89	0.95											
DDOR076	0.22	0.03		0.36		0.89	0.89											
DDOR113	0.02	0.00		0.39		[redacted]	[redacted]											
DDOR083	0.18	0.01		0.54		0.78	0.78											
DDOR109	0.10	0.01		0.61		[redacted]	[redacted]											
DDOR089	0.17	0.02		0.68		[redacted]	[redacted]											
DDOR091	0.01	0.00		0.54		[redacted]	[redacted]											
DDOR082	0.65	0.36		0.25		[redacted]	[redacted]											
DDOR131	0.00	0.02		0.89		0.52	0.77					FLAG					FLAG	
DDOR111	0.41	0.57		0.75		0.93	0.99											
DDOR110	0.09	0.01		0.82		0.85	0.86											
DDOR118	0.00	0.00		0.89		[redacted]	[redacted]					FLAG						
DDOR086	0.22	0.05		0.46		[redacted]	[redacted]											
DDOR104	0.06	0.05		0.14		0.91	0.95											FLAG
DDOR079	0.04	0.00		0.64		[redacted]	[redacted]											
DDOR094	0.31	0.01		0.11		0.52	0.67											
DDOR075	0.05	0.00		0.57		[redacted]	[redacted]											
DDOR080	0.05	0.00		0.46		0.76	0.63											
DDOR088	0.03	0.00		0.54		[redacted]	[redacted]											
DDOR090	0.50	0.25		0.68		[redacted]	[redacted]											
DDOR105	0.03	0.01		0.39		0.00	0.61										FLAG	
DDOR129	0.00	0.02		0.89		0.52	0.89					FLAG					FLAG	
DDOR130	0.00	0.03		0.89		[redacted]	[redacted]					FLAG					FLAG	
DDOR098	0.04	0.01		0.89		0.89	0.89											FLAG
DDOR106	0.02	0.01		0.25		0.98	1.00					FLAG						
DDOR102	0.04	0.00		0.54		0.80	0.70										FLAG	
DDOR115	1.00	1.00		0.64		0.96	0.98											
DDOR095	0.20	0.23		0.64		[redacted]	[redacted]											
DDOR128	0.02	0.06		0.89		0.52	0.89					FLAG					FLAG	
DDOR097	0.12	0.02		0.54		0.89	0.42											
DDOR103	0.11	0.01		0.00		0.85	0.64											
DDOR085	0.03	0.01		0.86		0.89	0.88											
DDOR126	0.01	0.02		0.96		0.52	0.44					FLAG					FLAG	
DDOR101	0.09	0.18		0.43		1.00	0.98											
DDOR127	0.00	0.03		1.00		[redacted]	[redacted]					FLAG					FLAG	
DDOR092	0.20	0.03		0.61		[redacted]	[redacted]											
DDOR112	0.48	0.19		0.75		[redacted]	[redacted]											
DDOR078	0.01	0.00		0.32		[redacted]	[redacted]											FLAG
DDOR077	0.02	0.01		0.71		0.52	0.89											FLAG
DDOR087	0.60	0.30		0.54		[redacted]	[redacted]											
DDOR093	0.06	0.01		0.39		0.80	0.38											
DDOR096	0.01	0.00		0.75		[redacted]	[redacted]											FLAG
DDOR084	0.18	0.21		0.86		0.98	0.99											

Project ID	Step 3: Determine Quantitative Metric Scores			Step 4: Rank Quantitative Metric Scores			Step 5: Assign RAG Scores				Step 6: Determine Final Score and Ranking			Approval Status
	Cost Effectiveness	Scaled Forecast Certainty	Market Assessment	Cost Effectiveness	Scaled Forecast Certainty	Market Assessment	Cost Effectiveness	Scaled Forecast Certainty	Market Assessment	Final RAG Score	Final Score	Final Ranking	Final Tiering	
DDOR081	0.24	1.50	1.47	13	12	27	0	0	FLAG	Tier 3	3.20	18	Tier 3	N/A
DDOR108	0.01	1.43	1.53	42	16	23	-1	0	0	-1	2.98	23	Tier 3	N/A
DDOR100	0.09	0.93	1.84	22	32	12	0	0	0	0	2.86	27	Tier 2	N/A
DDOR076	0.26	0.71	1.78	12	39	16	0	-1	0	-1	2.76	29	Tier 3	N/A
DDOR113	0.02	0.79	1.09	37	36	38	-1	-1	-1	-3	1.90	41	Tier 3	N/A
DDOR083	0.20	1.07	1.56	15	26	21	0	0	0	0	2.83	28	Tier 2	N/A
DDOR109	0.11	1.21	1.67	19	23	20	0	0	0	0	2.99	22	Tier 2	N/A
DDOR089	0.20	1.36	1.74	16	18	18	0	0	0	0	3.29	13	Tier 2	N/A
DDOR091	0.01	1.07	0.87	43	26	44	-1	0	-1	-2	1.95	40	Tier 3	N/A
DDOR082	1.01	0.50	1.95	2	41	4	1	-1	1	1	3.46	10	Tier 1	N/A
DDOR131	0.02	1.79	1.30	40	3	35	FLAG	1	FLAG	Tier 3	3.10	20	Tier 3	N/A
DDOR111	0.98	1.50	1.92	3	12	6	1	0	1	2	4.40	2	Tier 1	N/A
DDOR110	0.09	1.64	1.71	21	11	19	0	1	0	1	3.45	11	Tier 1	N/A
DDOR118	0.00	1.79	0.96	45	3	43	FLAG	1	-1	Tier 3	2.75	30	Tier 3	N/A
DDOR086	0.27	0.93	1.81	10	32	13	1	0	0	1	3.00	21	Tier 1	N/A
DDOR104	0.11	0.29	1.86	20	43	9	0	-1	FLAG	Tier 3	2.26	37	Tier 3	N/A
DDOR079	0.05	1.29	1.54	28	20	22	0	0	0	0	2.87	26	Tier 2	N/A
DDOR094	0.31	0.21	1.19	9	44	36	1	-1	-1	-1	1.72	42	Tier 3	N/A
DDOR075	0.05	1.14	0.98	25	25	41	0	0	-1	-1	2.17	38	Tier 3	N/A
DDOR080	0.05	0.93	1.39	26	32	32	0	0	0	0	2.37	36	Tier 2	N/A
DDOR088	0.04	1.07	1.48	32	26	26	0	0	0	0	2.59	32	Tier 2	N/A
DDOR090	0.75	1.36	1.88	5	18	8	1	0	1	2	3.99	5	Tier 1	N/A
DDOR105	0.04	0.79	0.61	29	36	45	0	-1	FLAG	Tier 3	1.44	45	Tier 3	N/A
DDOR129	0.02	1.79	1.41	39	3	30	FLAG	1	FLAG	Tier 3	3.22	17	Tier 3	N/A
DDOR130	0.03	1.79	1.41	35	3	30	FLAG	1	FLAG	Tier 3	3.22	16	Tier 3	N/A
DDOR098	0.05	1.79	1.78	27	3	15	0	1	FLAG	Tier 3	3.62	7	Tier 3	N/A
DDOR106	0.02	0.50	1.98	38	41	2	FLAG	-1	1	Tier 3	2.50	35	Tier 3	N/A
DDOR102	0.04	1.07	1.51	30	26	24	0	0	FLAG	Tier 3	2.62	31	Tier 3	N/A
DDOR115	2.00	1.29	1.94	1	20	5	1	0	1	2	5.22	1	Tier 1	N/A
DDOR095	0.43	1.29	1.90	7	20	7	1	0	1	2	3.62	8	Tier 1	N/A
DDOR128	0.08	1.79	1.41	23	3	29	FLAG	1	FLAG	Tier 3	3.27	14	Tier 3	N/A
DDOR097	0.14	1.07	1.32	17	26	34	0	0	0	0	2.53	34	Tier 2	N/A
DDOR103	0.12	0.00	1.49	18	45	25	0	-1	0	-1	1.61	44	Tier 3	N/A
DDOR085	0.04	1.71	1.77	31	9	17	0	1	0	1	3.52	9	Tier 1	N/A
DDOR126	0.02	1.93	0.97	36	2	42	FLAG	1	FLAG	Tier 3	2.92	24	Tier 3	N/A
DDOR101	0.27	0.86	1.98	11	35	1	1	-1	1	1	3.11	19	Tier 1	N/A
DDOR127	0.03	2.00	1.39	33	1	33	FLAG	1	FLAG	Tier 3	3.42	12	Tier 3	N/A
DDOR092	0.23	1.21	1.80	14	23	14	0	0	0	0	3.24	15	Tier 2	N/A
DDOR112	0.67	1.50	1.85	6	12	11	1	0	1	2	4.02	4	Tier 1	N/A
DDOR078	0.01	0.64	1.05	44	40	40	-1	-1	FLAG	Tier 3	1.70	43	Tier 3	N/A
DDOR077	0.03	1.43	1.41	34	16	28	0	0	FLAG	Tier 3	2.87	25	Tier 3	N/A
DDOR087	0.90	1.07	1.85	4	26	10	1	0	1	2	3.81	6	Tier 1	N/A
DDOR093	0.06	0.79	1.18	24	36	37	0	-1	-1	-2	2.03	39	Tier 3	N/A
DDOR096	0.01	1.50	1.08	41	12	39	-1	0	FLAG	Tier 3	2.59	33	Tier 3	N/A
DDOR084	0.39	1.71	1.97	8	9	3	1	1	1	3	4.07	3	Tier 1	N/A

Advice 6403-E
November 15, 2021

Attachment C

IPE DPAG Report

(Public)

REPORT

Independent Professional Engineer PG&E 2021 DPAG Report

PUBLIC VERSION

Submitted to California Public Utilities Commission Energy Division and PG&E

November 15, 2021

Contents

1 Introduction and Background

Summary of CPUC April 13, 2020, Rulemaking 14-08-013 and Other Rulemakings

The paragraphs that follow summarize the parts of the April 13, 2020, CPUC ruling and other rulings that directly impact the role of the IPE and/or this report.

The April 13, 2020, CPUC Ruling modified the Distribution Investment Deferral Framework (DIDF) process and filings with respect to the Independent Professional Engineer (IPE) scope of work and provided the updated 2020-2021 DIDF cycle schedule. Attachments A and B of the Ruling include a listing of the IPE-specific reforms discussed in the Ruling and the updated IPE scope of work. These Attachments of the Ruling are attached as Appendix A of this report.

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

The DIDF was implemented in 2018 and 2019 with the expectation that it would be evaluated and revised after each cycle to improve the process. To that end, the assigned Administrative Law Judge (ALJ) issued a Ruling Requesting Answers to Questions to Improve the Distribution Investment Deferral Framework Process on February 25, 2019 (February 25, 2019, Ruling). Based on these comments, the ALJ issued a Ruling Modifying the Distribution Investment Deferral Framework Process on May 7, 2019 (May 7, 2019, Ruling). The parties have proposed additional recommendations for DIDF reform throughout the 2019 DIDF cycle. A Ruling Requesting Comments on Possible Improvements to the 2020 Distribution Investment Deferral Framework Process was subsequently issued on November 8, 2019 (November 8, 2019, Ruling), and the contents of this Ruling further modify the DIDF. A Ruling on May 11, 2020, modified the DIDF filing and process requirements including proposing a number of possible reforms to the DIDF followed by a ruling in June 2021 establishing new reforms and modifying some of those included in the May 11, 2020, ruling.

The CPUC issued Ruling 14-10-003 on 2/12/21 titled Decision Adopting Pilots to Test Two Frameworks for Procuring Distributed Energy Resources that Avoid or Defer Utility Capital Investments. In that ruling the CPUC added two additional procurement mechanisms to the DIDF cycle and spelled out how pilots of these two mechanisms are to be implemented over the next few DIDF cycles. The two new mechanisms are called the Standard Offer Contract, which applies to in front of the meter DERs, and the Partnership Pilot, which applies to behind the meter DERs. The ruling also includes some revisions to the DIDF process and timing which are followed in this cycle's IPE review and this report.

The IPE scope of work outlined in Attachment A provides for improvement to the IPE review process based on comments received and clarifies that the development of IPE review plans for each IOU will be overseen and approved by Energy Division. According to the Ruling, it is important the IPE has sufficient time to prepare the IPE Plans in advance of the GNA/DDOR filings and that after the filings, the IPE has the cooperation and coordination of the IOUs necessary to collect the data needed for review in time to prepare the IPE Preliminary Analysis of GNA/DDOR Data Adequacy and IPE DPAG Report.

The revised IPE scope reflected in Ruling 14-08-013 includes the requirement to develop an IPE Plan that will cover most if not all of the IPE activities. A copy of the Final 2021 IPE Plan for PG&E is included in Appendix C.

According to the Ruling, planning standards that lead to the identification of reliability needs need not be reviewed at this time. Instead, the IOUs should provide the IPE with planning documentation that supports the identification of all reliability needs. At this time, a formal review of IOU planning standards is not required as it could be a significant undertaking. However, the Ruling states that the Energy Division should discuss the 2020 GNA/DDOR filings with the IPE to determine if inconsistencies and shortcomings in the IOU planning standards exist and whether further review should be prioritized for future DIDF cycles.

The April 13, 2020, CPUC Ruling goes on to state to further assist the IPE with DPAG Report completion, a new IPE Post-DPAG Report deliverable is included within the IPE scope of work. The IPE Post-DPAG Report should review and compare overall IOU DIDF compliance and make recommendations for process improvements and DIDF reform.

As stated in the May 7, 2019, Ruling, the IPE shall report directly to Energy Division to prepare its deliverables and conduct its analyses for DIDF implementation. The April 13, 2020, Ruling states the term of the IPE scope of work shall be the entire DIDF cycle, which starts on January 1 each year to plan for Pre-DPAG and DPAG implementation and concludes on July 31 the following year after all RFOs are concluded and all DIDF reforms are implemented. As a result, IPE scopes of work for each DIDF cycle will overlap.

The schedule and milestones established by the April 13, 2020, Ruling and as modified in subsequent rulings are shown below as they apply to the 2021/2022 DIDF cycle.

DPAG Schedule for 2021 DIDF Cycle

Activity	Date
Pre-DPAG 2021	
Pre-DPAG meetings and workshops, including Draft IPE Plans review	May 2021
DPAG 2021	
IOU GNA/DDOR filings, Final IPE Plans circulated	August 15, 2021
IOUs update DRP Data Portals with GNA/DDOR data	August 30, 2021
IPE Preliminary Analysis of GNA/DDOR data adequacy circulated	September 5, 2021
DPAG meetings with each IOU	September 15, 2021 (week of)
Participants provide questions and comments to IOUs and IPE	September 25, 2021
IOU responses to questions	October 5, 2021
Follow-up IOU meetings via webinar	October 10, 2021 (week of)
IPE DPAG Reports	November 15, 2021
DIDF Advice Letters submitted	November 15, 2021
Post-DPAG 2021 and 2022	

Provide draft RFO launch materials to Energy Division for approval in consultation with IPE and IE	December 10, 2020
Launch RFOs for DERs	January 15, 2021 (or within 30 days of DIDF Advice Letter approval if approval is after December 15, 2021)

Independent Professional Engineer

The California Public Utilities Commission (Commission) rulings direct Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (Utilities or IOUs) 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. (now a part of Resource Innovations), PG&E engaged Mr. Barney Speckman[1], PE, to serve as the advisory engineer (referred to as the Independent Professional Engineer (IPE) for the scope described in the April 23, 2020, CPUC Ruling are as modified by subsequent rulings.

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 IPE Plan

As required by the April 23, 2020, Ruling, the IPE developed an IPE Plan that served to guide the IPE's steps to implement its 2020 DIDF work scope. The plan was developed using a three-step process:

1. In step 1 the IPE developed a draft IPE Plan working with the Energy Division and PG&E by mid-May 2021.
2. The Plan was distributed to the service list and also discussed at the CPUC Distribution Forecasting Working Group meeting - both in an attempt to obtain stakeholder feedback on the plan.
3. Based upon stakeholder feedback received and under the direction of the Energy Division, the IPE revised the plan and made its IPE Final Plan available on August 25, 2021.

A copy of the Final IPE Plan is included as Appendix C.

The IPE Plan covers the business processes that PG&E uses to identify which distribution projects are recommended to proceed to an RFO seeking DER bids to determine if there is a cost-effective non-wires alternative. One of the core purposes of the plan is answer the question - Are the IOUs identifying every project that could feasibly and cost effectively be deferred by DERs?

The business processes in the Plan are organized generally in the order that they are performed. Starting with capturing the peak load values for each circuit for 2020, using the CEC IEPR forecasts to develop utility specific system level values which are then disaggregated to the circuit level adjusted for known loads and then used to determine if there is an overload or other issue during the planning period. For circuits that have a need, a planned project is selected to address one or more needs, capital costs developed for that project, and the planned projects/investments are screened to develop a list of potential candidate deferral projects. These candidate deferral projects are then prioritized into tiers using several metrics, with the projects in the first tier normally recommended for a DER RFO. In this cycle, for the first-time projects were also selected from

[1] 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.

the candidate deferral list to participate in the two new CPUC Pilots – the Standard Offer Contract and Partnership Pilot.

1.2 Definitions of Verification and Validation

As part of the development of the IPE Plan, detailed definitions were developed to clarify the meaning of Verification and Validation as applied to the IPE scope of work. These definitions which are used and applied in all IPE deliverables, are listed below:

Verification – Is a review performed by the IPE during which an independent check is performed to determine if the results produced were developed using data assumptions and business processes that were defined and described by the utility or are based upon standard industry approaches that do not have to be defined and described. In other words, "Did the IOU follow their own processes correctly as defined by the IOU?"

Validation – Is a review performed by the IPE during which an independent assessment is performed of the appropriateness of the approach taken by the utility to perform a task from an engineering, economics and business perspective. In other words, "Are the processes implemented by the IOU the best way to identify all planned investments that could feasibly be deferred by DERs cost effectively? And to what extent were the IOU methodologies appropriate and effective?"

1.3 Services Considered within the DDOR Framework

The CPUC, in a previous decision[2], 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.
>
> 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."

1.4 Approach to Information Collection

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

[2] Decision 16-12-036; definitions can be found on Page 8. Link to document below: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M171/K555/171555623.PDF

- Conference calls with PG&E held to review material, respond to IPE questions, and perform Verification and/or Validation Demonstration walk-throughs as described in the IPE Plan and whose results are described later in the report.
- Written data requests sent to PG&E regarding their planning process that led 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. All written requests and responses were provided through a secure file transfer protocol established by PG&E. A copy of documents provided in response to these requests are included as Appendix D.
- Participation in PG&E's DPAG Webinar (September 20) and its follow up DPAG Webinar (October 22).
- A review of publicly available materials referred to in the discussions with PG&E or materials previously filed with the CPUC.

1.5 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, and any significant differences noted in PG&E's reports between the 2021 and 2020 DIDF cycle. Observations, comments, and recommendations that result from the Validation review with respect to the GNA Report are included in this section.
- Section 3 – Review of DDOR Report which briefly discusses the contents of the PG&E DDOR Report, and any significant differences noted in PG&E's reports between the 2021 and 2020 DIDF cycle. Observations, comments, and recommendations that result from the Validation review with respect to the DDOR Report are included in this section.
- Section 4 – Review of Screening and Prioritization which discusses the screening and prioritization process and results. Observations, comments, and recommendations that result from the Validation review with respect to the screening and prioritization are included in this section.
- Section 5 – Review of Candidate Deferral Projects which includes the review of projects that have been placed into the Tiers defined by PG&E. Observations, comments, and recommendations that result from the Validation review with respect to the placement of projects in the PG&E defined Tiers are included in this section.
- Section 6 – Discussion of Other Topics of Interest. Observations, comments, and recommendations that result from the Validation review with respect to these topics are included in this section.
- Section 7 – Verification completed which reviews the approach and results of the verification performed by the IPE.
- Appendix A – IPE Scope - Excerpt from April 23, 2020, CPUC Rulemaking 14-08-013.
- Appendix B – Comments Received from the DPAG Members and IOU and IPE responses.
- Appendix C – IPE Final IPE Plan – PG&E
- Appendix D – Documents Received

Identifying Confidential Information

There are a number of instances where information is confidential and such information is highlighted in gray in the confidential version of the Report and blacked out (redacted) in the Public Version of the Report. These are data elements that are considered confidential by PG&E because they are entries for projects that meet the 15/15 Rule or are otherwise declared confidential by PG&E. They include, but are not limited to, such things as GNA and DDOR report appendices, PV and LMDR profiles, charging and discharging, and disaggregation information, etc.

This PUBLIC VERSION of the report can be distributed to any interested party since it does not include any confidential information

.

2 Review of GNA Report

The GNA Report submitted by PG&E is summarized at a high level below.

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

The PG&E Grid Needs Assessment (GNA) Report is a written report including several Appendices, Appendix D: GNA Results - DER Growth Forecast, Appendix E: GNA Results – Bank & Feeder Capacity Needs, Appendix F: GNA Results – Reliability/Resiliency Needs and Appendix G: GNA Results – Line Section Capacity and Voltage Needs. These Excel-based workbooks provide the potential grid needs on PG&E's 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 16, 2021, as required by the CPUC. As approved on August 10, 2021, in PG&E's Motion for Extension of Time to File Limited Portions of the Grid needs Assessment, Distribution Deferral Opportunity Report and Corresponding Publication to the Data Portal, PG&E published a Supplemental GNA and DDOR Report on October 15, 2021, with line section grid needs and planned investments and published this data on the DRP Data Portal on October 30,2021. PG&E does not plan to revise the reports themselves since no candidate deferral opportunities were identified in the supplemental filing (due to timing screen).

Summary of PG&E's 2020 GNA Report

The GNA covers all identified substation, distribution circuit and circuit/segment[3] level needs after free or no-cost load transfers have been reflected in load forecasts. The needs listed include among other information, the following:

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

2.2 Changes to GNA for 2021

PG&E received a Motion for Extension approval on August 10, 2021, to delay publishing of grid needs resulting from line section analyses, which are primarily voltage support and distribution capacity needs. PG&E provided a supplemental filing on October 15, 2021, per the approved Motion for Extension. The GNA and DDOR were not revised because no candidate deferral opportunities were identified in the supplemental filing (due to timing screen).

For reliability improvement, PG&E has a goal of reducing the number of customers on a circuit to less than 6000. In previous GNA reports, these projects were identified and categorized as a Reliability Need. In 2021, this type of project is identified as a Resiliency (Micro-Grid) Need. This is discussed later in 2.3.5 Resiliency (Micro-Grid) Needs.

2.3 Basis for GNA

The basis for the GNA is the disaggregated PG&E load forecast which is discussed later in Section 7. We observe that PG&E accepts the CEC system load growth forecast over the ten-year planning horizon and does

[3] Line section needs were provided in a supplemental filing on October 15, 2021.

not add incremental local growth projects (also referred to as incremental known load projects) in their system forecasting process that exceeds the total load growth in the IEPR forecast. Thus, the aggregate ten-year load growth excluding DERs in the PG&E system level forecasts is the same as the CEC's.

As we discuss below, PG&E incorporates its known growth project loads in a way that changes the annual growth compared to the CEC annual load growth values which can result in annual load growth larger than the CEC annual growth in some years and annual load growth in other years that is smaller than growth than the CEC annual growth. The net result is that the cumulative load growth over the ten years used by PG&E is the same as reflected in the IEPR.

We can see in the Figure 2-1 below, the result of this approach to the application of known loads – the aggregate load growth in the PG&E forecast is higher than the IEPR aggregate load growth until year 10 when the values are the same. As seen in the Figure, the cumulative known load after three years is greater than the cumulative IEPR forecast for the same period by over 750 MW. Therefore, the load forecast used in the GNA for the first three years is substantially higher than the CEC IEPR forecast. Starting with year four, the GNA forecast and the IEPR aggregate forecast begin to converge and finally converge in year 10. This is a result of the limited number of applications and therefore new known loads in the later years. It is observed this approach will likely result in more investment in the earlier years than if the IEPR forecast was used without adjustments.

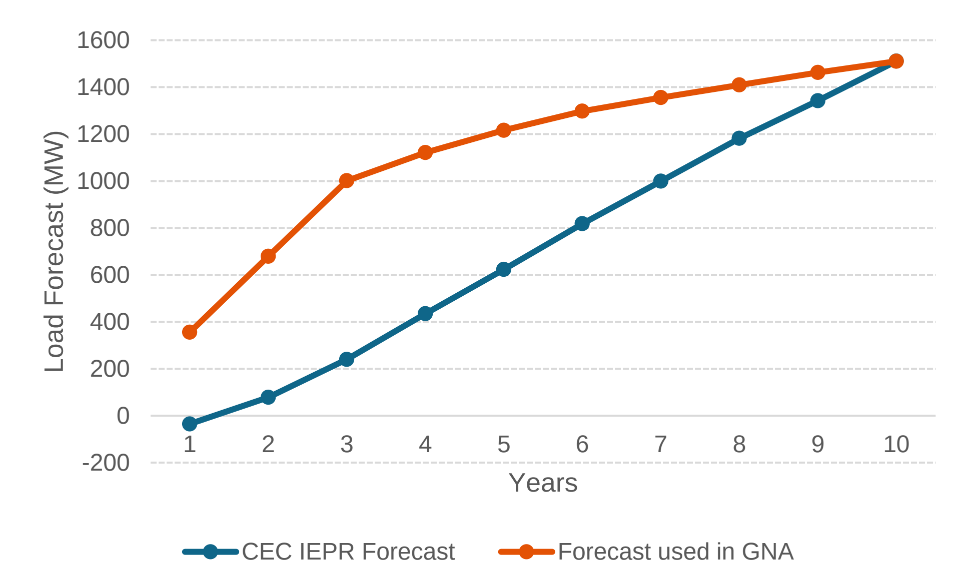


Figure 2-1; Comparison of IEPR and Load Forecast Used for GNA

2.4 GNA Results

2.4.1 Needs and In-service or Operational Dates

A summary of needs and associated in-service or operational dates can be seen in Table 2-1 and Table 2-2, which are tables included in PG&E's GNA Report and duplicated here for convenience.

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

Facility Type	Distribution Service				Total
	Distribution Capacity*	Voltage Support*	Reliability (Back-Tie) *	Resiliency (Microgrid)	
Substation /Bank	121	0	6	2	**129**
Feeder	224	0	7	18	**249**
Distribution Line*	0	3	11	0	**14**
Totals	**345**	**3**	**24**	**20**	**392**

*Additional Grid Needs and associated Planned Investments resulting from line section analysis will be provided as a supplemental filing on October 15, 2021

Table 2-2: Summary of All Grid Needs by Anticipated Need Date

Anticipated Need Date					Total
2021	2022	2023	2024	>2025	
276	66	25	17	8	**392**

2.4.2 Distribution Capacity Needs

The majority of the Grid Needs are Distribution Capacity needs. Of the 345 needs in this category, 322 are needed within the next 3 years, leaving 23 capacity needs with Anticipated Need Dates of 2024 or later.

PG&E has two Distribution Capacity Needs, Blackwell Bank 1 and Huron Bank 1, that are designated as DER Driven which are driven by backflow from PV solar generation on the distribution system. PG&E has proposed two non-DER Planned Investments, Blackwell Bank 1 and Huron Bank 1, to mitigate these needs. These Planned Investments are discussed briefly later in Section 3.1

2.4.3 Voltage Support Needs

Most Voltage Support Needs are associated with line sections. PG&E received approval on August 10, 2021, for an extension of time to complete its line section analysis. Any Grid Needs and related Planned Investments for line segments were provided in a supplemental filing on October 15, 2021. All of those identified needs had an Anticipated Need Date within the next three years, therefore, there are only three voltage support Candidate Deferral Opportunities identified in the GNA.

2.4.4 Reliability (Back-Tie) Needs

PG&E identified 24 Reliability or Back-Tie Needs. All of these needs but one had an Anticipated Need Date of less than three years.

2.4.5 Resiliency (Micro-Grid) Needs

PG&E identified 20 Resiliency Needs. All but one of these needs had an Anticipated Need Date of less than three years. Eighteen of the needs were for feeders with greater than 6,000 customers. As mentioned earlier, in prior years, these needs were categorized as a Reliability Need. PG&E justified this change by stating "In order for a DER solution to provide a reliability benefit in the same manner as reducing customer count on a circuit, a set of customers on the circuit would need to be immediately served by other means during an outage. This can be accomplished by islanding a part of the circuit so that those customers are not affected by the outage." This is consistent with the design goal stated in PG&E's, Guide for Planning Area Distribution Facilities, dated 8/5/18. This guide states "The feeder design goal is to limit the total number of customers to no more than 6,000."

2.5 GNA - Observations, Conclusions and Recommendations

We observe the of total number of substation/bank and feeder[4] Needs increased from 329 in 2020 to 378 in 2021. The change was a result of increases in substation/bank and feeder Distribution Capacity Needs. There was no explanation for this change, but it is expected the number of needs will vary each year.

It was also noted there was an increase in feeder Resiliency Needs with a corresponding decrease in feeder Reliability Needs. This is a result of changing the need category for circuits with greater than 6,000 customers from reliability to resiliency which is consistent with PG&E's planning guidelines.

As mentioned earlier the line section analysis was performed but not included as part of the GNA Report. We observe that PG&E has requested that line section needs not be included in the GNA. The need for mitigation projects for this analysis is near term and these investments will not pass the timing screen as PG&E has noted. <u>We recommend that the utilities not be required to submit line section data in the GNA.</u>

As mentioned in Section 2.3, the load forecast in the early years of the GNA is substantially higher that the IEPR forecast due to known new loads. The higher forecast in the first three years may pull the needs from later years into the years one through three which DERs are unable to defer due to the timing screen. Since these known loads in the first three years have a significant impact on planning and the DIDF process, <u>the IPE recommends that PG&E gather data that will track how many of these known loads materialize each year.</u> This information can then be used to adjust the known load additions in future cycles. <u>We recommend the IPE review this data as part of its annual review.</u>

[4] Distribution line needs are not included because PG&E did not update the GNA report to include the results of the line section analysis.

3 Review of DDOR Report – Planned Investments

Using the GNA as the foundation, the DDOR identifies Candidate Deferral Opportunities (CDOs) for potential competitive solicitation for cost-effective Distributed Energy Resource (DER) solutions to mitigate the identified distribution system needs. The DDOR also includes descriptions of the methodology used to prioritize CDOs for potential solicitation and procurement and the methodology used to identify CDOs for inclusion in the two pilot frameworks for procuring DERs, the Partnership Pilot and the Standard Offer Contract (SOC) Pilot.

The PG&E DDOR report covers all needs identified in the GNA and includes an Appendix with five Excel-based workbooks each containing several tabs: Appendix A: Planned Investments and Appendix B: Candidate Deferral Opportunities, with tabs for “Planned Investments” and “Candidate Deferral Opportunities”; Appendix C: Prioritization Metrics (Tiers) with tabs for “Tiers Summary, “Introduction”, “Summary Pivot”, “Prioritization Metrics Template”, “Candidate Deferral Inputs”, ”LNBA Inputs”, “Certainty Score”, and 1515_1or More Needs”; Appendix D: LNBA-Candidate Deferral Opportunities – Project Specific Inputs, with tabs “Overview”, “General Inputs”, “LNBA Results – Candidate Deferrals ”, and “Project Specific Inputs”; Appendix E: LNBA-Planned Investments - Worksheet Overview, with tabs “Overview”, “General Inputs”, “LNBA – Planned investments”, and “Project Specific inputs”, and Appendix G; Forecast Questionnaire Results (Certainty Score) with one tab for “Certainty Scores”. There is also an Appendix F in the DDOR which has a sample Forecast Questionnaire.

The data reflected in these workbooks represents a portion of PG&E’s traditional infrastructure projects that are planned to 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 GNA identifies 392 grid needs and since projects often fulfill multiple needs, the DDOR identifies 254 associated projects that are potential DDOR opportunities. The DDOR Appendix C Candidate Deferral Input tab identifies the 45 candidate deferral projects proposed by PG&E for further consideration. The DDOR Appendix C Prioritization Metrics Template tab summarizes the individual deferral candidates and their respective raw and normalized metric component evaluations. The use of the Prioritization Metrics to prioritize candidate deferral projects is described in more detail later in this report.

The figure below provides an illustration of the process followed by PG&E to identify CDOs based on GNA data.

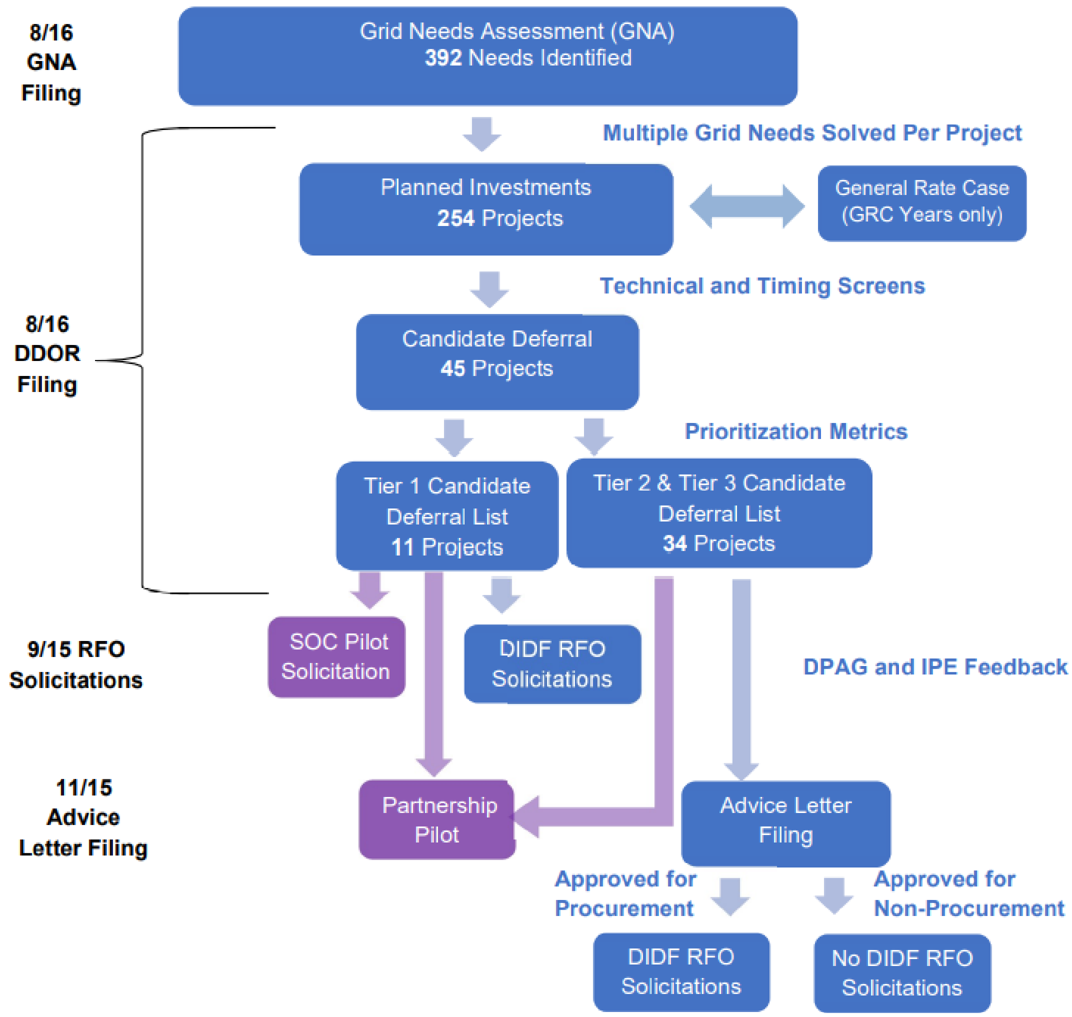


Figure 3 1: Process to Identify Candidate Deferral Opportunities

A summary of the 254 identified 2021 DDOR Planned Investments can be seen in the tables below from PG&E's DDOR Report.

Distribution Line projects make up 41% of the projects while feeders and substation project make up 41% and 18% respectively as shown in Table 3-1.

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

Distribution Planning Region	Project Type			Total
	Substation/Bank*	Feeder*	Distribution Line*	
Bay Area	5	31	12	**48**
Central Coast	15	24	33	**72**
Central Valley	19	34	37	**90**
Northern	7	15	22	**44**
Totals*	**46**	**104**	**104**	**254**

** Additional Grid Needs and associated Planned Investments resulting from line section analysis provided as a supplemental filing on October 15, 2021, were identified but not included in this table.*

Distribution capacity service needs make up 90.6% of the service requirements as can be seen in Table 3-2.

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

Distribution Service				Total
Distribution Capacity	Voltage Support *	Reliability (Back-Tie)	Resiliency	
230	**0**	**12**	**12**	**254**

**Additional Grid Needs and associated Planned Investments resulting from line section analysis provided as a supplemental filing on October 15, 2021, were identified but not included in this table.*

Table 3-3 shows 82.3% of the needs or 209 projects have an in-service or operational date earlier than 2024.

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

In-Service Date						Total
2021	2022	2023	2024	2025	2026	
59	90	60	34	9	2	254

IOU Ownership

PG&E has one DER solution planned for IOU ownership, Renz Energy Storage; and PG&E also sought bids for IOU ownership for Blackwell Bank 1 during the 2020-2021 DIDF RFO cycle. Renz Energy Storage is a Planned Investment for a DER solution planned for IOU ownership. PG&E is soliciting offers for the development of this energy storage system on PG&E-owned land as a deferral for the upgrade of a Llagas substation transformer.

The Blackwell Bank 1 Planned Investment was evaluated as a CDO in the 2020 DDOR and bids were sought for IOU ownership for this bank during the 2020-2021 DIDF RFO cycle. No cost-effective bids were received. This Planned Investment is being re-evaluated as a CDO in this 2021 DDOR. The needs and requirements have not changed but the ranking process for this year has the Blackwell Bank 1 as a Tier 2 project. This Tier change is because the ranking is done relative to the current year list of CDOs and there are other CDOs that ranked higher than Blackwell Bank 1. Because of the 2025 in-service date, Blackwell Bank 1 is expected to be in next year's DIDF when it will again be considered as a CDO.

DER-Driven Projects

PG&E has two Planned Investments for a DER driven Distribution Capacity need, Blackwell Bank 1 and Huron Bank 1. Both Planned Investments are replacements of substation banks because backflow caused by photovoltaic generation on the distribution system is projected to exceed the normal rating of the bank.

The Blackwell Bank 1 CDO was discussed above under IOU Ownership,

The second project, Huron Bank 1, has already completed the solicitation and contracting processes and has received approval for a DER solution.

3.1 DDOR Report Planned Investments - Observations, Conclusions and Recommendations

We observe that the total number of substation/bank and feeder projects for 2021 is very similar to the number in 2020 (150 vs. 157). As mentioned earlier, there is no reason to expect a major change in the number of these types of projects.

PG&E's changing the category of Distribution Service for feeders with greater than 6,000 customers changed the number of Grid Needs between the Reliability (Back-Tie) and Resiliency (Microgrid) categories but doesn't appear to have changed the number of CDOs.

4 DDOR Report - Review of Screening, Prioritization and Selection of Pilot Projects

This section contains a discussion of the two screens used by PG&E used to develop its candidate deferral project list. The screens, required by D.18-02-004, are a technical screen and a timing screen.

4.1 Project Screens

The first screen used 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 Distribution 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 2024 or later in-service date is considered as adequate lead time. Since the GNA needs analysis covers the years 2021 to 2026, the timing screen eliminates all projects other than those with in-service dates starting in 2024, 2025, and 2026. 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 a needs determination. This process is described in detail in the GNA/DDOR reports and discussed in Section 7 – Verification Approach and Results.

The technical screening is implemented as part of the development of the project list. If a capital project, such as a pole replacement or road widening project, cannot be mitigated by one of the four services mentioned it is not included in the GNA as a need. The technical screen can be considered as a continuous process as opposed to being performed at a single point in time. Therefore, the number of projects screened out because of technical concerns is not available from the data. Of the 254 projects that meet the technical requirements as a CDO, only 45 projects have in-service or operational dates of 2024, 2025, or 2026.

As seen in Table 4-1, 58% of the projects are substation/bank, 29% are feeder and 13% are distribution line.

Table 4-1: Summary of Candidate Deferral Opportunities by Project Type and Distribution Planning Region After Screening

Distribution Planning Region	Project Type			Total
	Substation/ Bank	Feeder	Distribution Line	
Bay Area	3	0	2	**5**
Central Coast	7	5	4	**16**
Central Valley	11	4	0	**15**
Northern	5	4	0	**9**
Totals	**26**	**13**	6	**45**

Table 4-2 shows, 85% of the projects provide Distribution Capacity and the remaining 15% of the projects provide Resiliency service.

Table 4-2: Summary of Candidate Deferral Opportunities by Distribution Service After Screening

Distribution Service				Total
Distribution Capacity	Voltage Support	Reliability (Back-Tie)	Resiliency (Micro-Grid)	
38	0	0	7	**45**

After screening, 75% of the projects have an in-service date of 2024, 20% have an in-service date of 2025 and 5% have an in-service date of 2026 as shown in Table 4-3.

Table 4-3: Summary of Candidate Deferral Opportunities by In-Service Date After Screening

In-Service Date						Total
2021	2022	2023	2024	2025	2026	
0	0	0	34	9	2	**45**

4.2 Project Prioritization

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

PG&E used the Prioritization Metrics Workbook Template jointly developed by the three IOUs and approved by the Energy Division on May 18, 2021. As in prior years, the prioritization process included three prioritization metrics – Cost Effectiveness, Forecast Certainty, and Market Assessment. However, some of the sub-metrics and how they were evaluated have changed.

The relative ranking of the individual metrics and each Deferred Candidate Opportunity is identified with a color code as shown in Table 4-4.

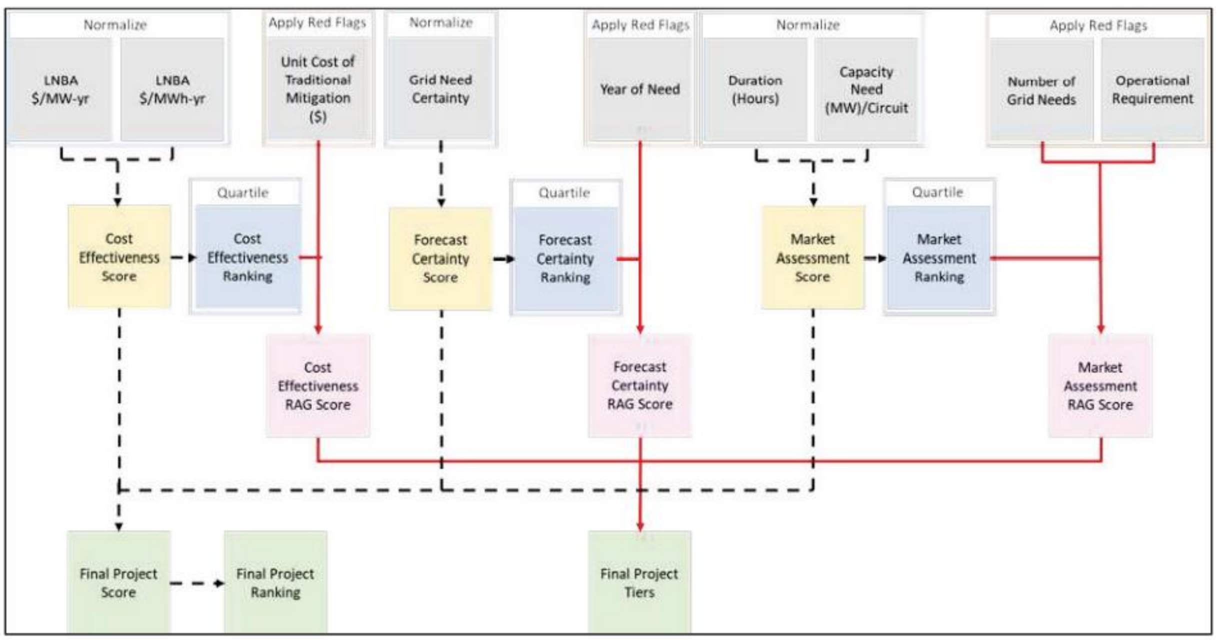
Table 4-4: 3-Tier Prioritization System

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

All rankings are 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. It only indicates the ranking of the Candidate Deferral Opportunity relative to other Candidate Deferral Opportunities.

The Joint Prioritization Metrics Workbook Template places CDOs into three tiers based on a step-by-step process, as illustrated in Figure 4-1. The development of the three-prioritization metrics is based on the evaluation of the sub-metrics of each of the three metrics. Each metric has two to four sub-metrics for a total of nine sub-metrics. Five of the sub-metrics are normalized and four are flagged if they don't meet a certain requirement. The five quantitative sub-metrics are normalized first (based on the maximum and minimum values for each sub-metric). The normalized values for each sub-metric are summed[5] to create a score for each Prioritization Metric. Each of the three Prioritization Metric scores are separated into quartiles. The top quartile of Prioritization Metric scores is assigned a "1", the middle two quartiles assigned a "0", and the bottom quartile assigned a "-1". These are known as the Red-Amber-Green (RAG) score. If one of the sub-metrics is flagged for a given Prioritization Metric, that Prioritization Metric is flagged. The total RAG score for each Candidate Deferral Opportunity is then summed across the three Prioritization Metrics. Those with a total RAG score greater than zero are placed in Tier 1; those with a total RAG score of zero are placed into Tier 2; and those with a total RAG score less than zero are placed into Tier 3. As the total RAG score is summed across the three Prioritization Metrics, a Candidate Deferral Opportunity can be assigned a "-1" for one of the Prioritization Metrics (e.g., Forecast Certainty) and still be placed into Tier 1. However, if any of the sub-metrics are flagged, the Candidate Deferral Opportunity will be placed into Tier 3 automatically.

Figure 4-1: Prioritization Metrics, Final Scoring, and Tiering



Prioritization Metrics Included in Joint Prioritization Workbook Template

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 two quantitative sub-metrics, Estimated LNBA ($/KW-yr.) and Estimated LNBA ($/MWh-yr). The LNBA-related metrics are developed by taking the deferral value for the project and dividing that value by the summation of all maximum MW needs associated with project during the deferral period and the maximum MWh-yr. For the metric evaluation, these two sub-metrics are normalized and added together. For informational purposes only, the Estimated LNBA ($/MWh-day) value for each Candidate Deferral Opportunity is also shown. The MWh-day value is the maximum energy need for the day of the forecasted peak demand. There is also one sub-metric, Cost of Traditional Mitigation, which is flagged if the cost is less than $1 million. The Unit Costs are the estimated project capital costs at the time of the report. This topic is discussed further in Section 7.3.

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

[5] The Forecast Certainty Metric is based on one sub-metric and therefore is weighted by a factor of 2 (the other Prioritization Metrics have two quantitative sub-metrics summed with equal weighting).

- High unit cost of a traditional solution.
- High LNBA ($/kW-year); and
- High LNBA per MWh of deferral ($/Megawatt-hour (MWH)-year).

The Forecast Certainty Metric is intended to give a relative indication of the certainty of the forecasted grid need. This metric contains two components, a Grid Need Certainty Score and a Year of Need.

The Grid Need Certainty Score is developed from a Forecast Questionnaire, which PG&E introduced last year. This questionnaire, completed by local distribution engineers, provides local engineering judgement potentially impacting the certainty of the forecast, such as the health and condition of assets and other activity in the area which may impact the forecast loading. The questionnaire asks about the likelihood that the area served by the asset will connect to new EV charging stations, new cannabis cultivation, new agricultural pumps or new high-tech growth, including campuses and data centers. The questionnaire also asks how strongly load is inversely proportional to State and Federal water allocation, how strongly load correlates to temperature, how much the project impacts area capacity, how the much the Candidate Deferral Project will impact the operational flexibility of the system, and the impact of the area based on COVID-19 adjustments. The Forecast Questionnaire is an attempt to standardize local input for these major projects. See Section 4.2.1 for additional discussion of the Forecast Questionnaire.

The Forecasted Year of Need identifies the earliest Anticipated Need date of all the Grid Needs associated with that particular Candidate Deferral, as derived from the LoadSEER forecast. PG&E considers needs in later years as having more uncertainty. This is a flagged sub-metric that identifies CDOs with a year of need of 2026 and beyond.

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

- Nearer term need (2024 vs. 2025); and
- A higher (less negative) Grid Need Certainty Score from the Forecast Questionnaire completed by the distribution engineers.

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 four sub-metrics. Two quantitative sub-metrics, Duration (hours) and Capacity Need (MW/circuit), are normalized and summed. The other two sub-metrics, Operational Requirement (Real Time or Day Ahead) and Number of Grid Needs, are flagged sub-metrics.

For the Duration (hours) sub-metric, a project with shorter duration receives a higher quantitative score. For a CDO with one need location this value would be the CDO's DER duration needs as determined in the planning process. For CDOs with multiple needs the value would be the maximum duration of any of the need locations included in the project.

The Capacity Need (MW) per Circuit sub-metric receives higher quantitative scores for CDOs that have less capacity needed per circuit which can be met by the DER.

The Operational Requirement sub-metric is flagged when the requirement is Real Time because it is believed developers may view a Real Time five-minute dispatch notice to be too difficult and costly to achieve in practice and likely to impact potential revenue streams.

For the Number of Grid Needs sub-metric, a CDO with more than three grid needs is flagged. The reason for this is implementing DER solutions for fewer locations will be easier (and less costly) than implementing DER for many locations.

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

- Day Ahead, rather than Real Time, operational requirement.
- Low number of electric facilities experiencing grid needs in the CDO.
- Shorter duration

As mentioned above, numerical values are determined for each prioritization metric and each of the three prioritization metrics are divided into quartiles based on these scores. Metrics in the first quartile receive a RAG score of one, metrics in the second and third quartile receive a RAG score of 0, and metrics in the fourth quartile receive a score of -1. The three prioritization metric RAG scores for each CDO are summed and those CDOs with a sum greater than 0 are placed in Tier 1; those with a sum of zero are placed in Tier 2; and those with a score of less than zero are placed in Tier 3. Any CDO with a Red Flag is automatically placed in Tier 3.

The results of the application of these three metrics are shown in Table 4-5 below.

Table 4-5: Preliminary Prioritization Metrics and Rankings of Candidate Deferral Opportunities

Note: This table has confidential information highlighted in gray which was redacted in this public report

Tier	DDOR ID	Candidate Deferral	In-Service Date	Deficiency (MW)	Cost Effectiveness	Forecast Certainty	Market Assessment
Tier 1	DDOR082	Coalinga No 1 Bank 2	5/1/2024		1	-1	1
Tier 1	DDOR111	Embarcadero (SF Z) 1116	4/1/2026	0.3	1	0	1
Tier 1	DDOR110	Embarcadero (SF Z) 1118	6/1/2025	1.3	0	1	0
Tier 1	DDOR086	French Camp Bank 1	5/1/2024		1	0	0
Tier 1	DDOR090	Lakeview 1110	5/1/2024		1	0	1
Tier 1	DDOR115	Mormon Bank 2	6/1/2025	1.1	1	0	1
Tier 1	DDOR095	Newhall Bank 3	6/1/2024		1	0	1
Tier 1	DDOR085	Ripon 1705	5/1/2024	5.9	0	1	0
Tier 1	DDOR101	Rocklin 1105	5/1/2025	0.7	1	-1	1
Tier 1	DDOR112	Saratoga 1102	5/1/2026		1	0	1
Tier 1	DDOR087	Vierra Bank 3	5/1/2024		1	0	1
~~Tier 1~~	~~DDOR084~~	~~Zamora 1108~~	~~5/1/2024~~	~~1.1~~	~~1~~	~~1~~	~~1~~
Tier 2	DDOR100	Anita 1105	6/1/2024	3.8	0	0	0
Tier 2	DDOR083	Belle Haven Bank 4	5/1/2024	3.9	0	0	0
Tier 2	DDOR109	Blackwell Bank 1	6/1/2025		0	0	0
Tier 2	DDOR089	Bonita Bank 2	5/1/2024		0	0	0
Tier 2	DDOR079	Gabilan Bank 2	5/1/2024		0	0	0
Tier 2	DDOR080	Green Valley Bank 3	5/1/2024	6.2	0	0	0
Tier 2	DDOR088	Hammonds Bank 1	5/1/2024		0	0	0
Tier 2	DDOR097	Plainfield Bank 1	6/1/2024	4.7	0	0	0
Tier 2	DDOR092	San Miguel Bank 2	6/1/2024		0	0	0
Tier 3	DDOR081	Airways Bank 3	5/1/2024	4.5	0	0	FLAG
Tier 3	DDOR108	Ames 1103	6/1/2025		-1	0	0
Tier 3	DDOR076	Arbuckle Bank 2	4/1/2024	2.1	0	-1	0
Tier 3	DDOR113	Banta Bank 1	5/1/2024		-1	-1	-1
Tier 3	DDOR091	Chualar Bank 1	5/1/2024		-1	0	-1
Tier 3	DDOR131	Edenvale 2108	10/1/2024	2.0	FLAG	1	FLAG
Tier 3	DDOR118	Extend Edenvale 2111 to 2112	4/2/2024		FLAG	1	-1
Tier 3	DDOR104	Fulton Bank 5	5/1/2025	4.8	0	-1	FLAG
Tier 3	DDOR094	Garberville Bank 2	6/1/2024	11.3	1	-1	-1
Tier 3	DDOR075	Giffen Bank 2	4/1/2024		0	0	-1
Tier 3	DDOR105	Lockeford Bank 1	5/1/2025	19.5	0	-1	FLAG
Tier 3	DDOR129	Martin (SF H) 1107	10/1/2024	1.1	FLAG	1	FLAG
Tier 3	DDOR130	Martin (SF H) 1108	10/1/2024		FLAG	1	FLAG
Tier 3	DDOR098	Mc Kee 1102	6/1/2024	6.3	0	1	FLAG
Tier 3	DDOR106	Molino Bank 1	6/1/2025	0.8	FLAG	-1	1

Tier 3	DDOR102	Montague Bank 2	5/1/2025	7.6	0	0	FLAG
Tier 3	DDOR128	Oceano 1106	10/1/2024	1.1	FLAG	1	FLAG
Tier 3	DDOR103	Rincon Bank 1	5/1/2024	6.1	0	-1	0
Tier 3	DDOR126	Rob Roy 2105	10/1/2024	4.6	FLAG	1	FLAG
Tier 3	DDOR127	Salinas 1102	10/1/2024		FLAG	1	FLAG
Tier 3	DDOR078	Spence Bank 2	5/1/2024		-1	-1	FLAG
Tier 3	DDOR077	Storey 1103	5/1/2024	4.3	0	0	FLAG
Tier 3	DDOR093	Willow Pass Bank 1	6/1/2024	10.2	0	-1	-1
Tier 3	DDOR096	Wolfe 1111 & Wolfe 1112	6/1/2024		-1	0	FLAG

Zamora 1108 was a Tier 1 CDO which was proposed to meet 2 grid needs – relieve overloads on Knight's Landing Bank 1 and on Zamora Bank 1. On September 1, 2021, the voltage regulator at Knight's Landing Substation failed resulting in an emergency replacement. The emergency work included the replacement of the Knight's Landing transformer and voltage regulator with a transformer with an internal load tap changer, rather than a separate voltage regulator. Both the failed regulator and existing transformer were installed in 1963. This replacement addressed the need for the Zamora 1108 circuit.

4.2.1 Project Prioritization - Observations Conclusions and Recommendations

Prioritization Metrics

- Joint Prioritization Metrics Workbook

  We observe PG&E used the Prioritization Metrics Workbook Template that was jointly developed by the three IOUs and approved by the Energy Division on May 18, 2021. As in prior years, the prioritization process included three prioritization metrics – Cost Effectiveness, Forecast Certainty, and Market Assessment. However, some of the sub-metrics and how they were evaluated were changed as discussed above.

  We observe the Prioritization Metrics Workbook uses a more quantitively evaluation approach than PG&E used previously.

  We observe that while the IOUs are using a common approved methodology (Prioritization Metrics Workbook), the evaluation of some of the quantitative sub-metrics and the use of the flagged sub-metrics vary considerably across the IOUs. For example, one metric concerns the uncertainty of the load forecast (new load growth). When PG&E evaluates this metric, it is concerned about the possibility of additional new load materializing that was not forecasted. Yet another IOU's evaluation focuses on the possibility of the forecasted load not developing. The two IOUs are using this same metric to consider two different forecasts risks. We recommend that this particular issue be an agenda item for the next DIDF reform stakeholder webinar early in the next DIDF cycle.

  In addition, PG&E considers flagged sub-metrics as firm "go-no go" values resulting in placing CDOs in Tier 3 if it has a flagged sub-metric. On the other hand, another utility is still considering how to apply some of the flagged sub-metrics. This could be a result of the initial implementation of the Prioritization Metrics Workbook. We recommend that IOUs clarify their intended use of flags to the ED prior to the 2022/2023 DIDF cycle.

- The Forecast Questionnaire is source of information for the only quantitative sub-metric for the Forecast Certainty Metric, which is intended to give a relative indication of the certainty of the forecasted grid need. The questionnaire basically contains three parts:

- One question concerns a transformer bank that is being replaced on a capacity project. It asks about the risk of the bank failing based on its condition. (PG&E plans to reword this question based on the experience with the Zamora 1108 CBO this year.) The concern here appears to be the need to replace this asset after the DER solution is implemented.
- Seven questions concerning the certainty of the forecast. These questions ask about potential unforeseen loads that could materialize. These are new loads that are not associated with a current customer request for new service. Four questions address potential new loads include EV charging, new cannabis cultivation facilities, new agricultural pumping load, and high-tech campuses and data centers. Three of these questions ask about the potential impact of Covid, the correlation of the load State and Federal water allocation, and the correlation of the load to temperature.
- Five questions regarding the type of operational benefits the CDO provides. These operational benefits range from new distribution ties to new substations.

We observe two of the questions address forecast risks that are already considered as part of the load forecasting process – these are questions related to the correlation of water allocation and temperature which are considered during the load forecast itself and it is unclear why these should be considered again in this sub-metric.

We observe the five questions regarding operational benefits are not related to the certainty of the grid need as identified by the GNA. This is not to imply operational benefits are not important, they are. But it does not appear appropriate to include them in the sub-metric of Forecast Certainty.

We observe the non-forecast related questions (question concerning potential bank failure and the operational flexibility questions) can contribute up to 50 percent of the score for this metric.

We observe a potential unintended consequence of this approach is that the operational benefit scoring could tend to score higher cost projects less favorably than the lower cost projects. For example, a new feeder project could score better than a substation project because of the operational flexibility scoring approach and the feeder project would typically be less expensive than the substation project.

When discussing the Forecast Questionnaire with PG&E, they mentioned a concern of implementing a DER solution and then not being able to serve an unexpected new load when required because there was no margin in the system because a DER solution is selected. When they utilize a DER solution, they get exactly what is needed at the time. If they utilize a traditional utility solution, they often get more capacity than they need at the time because of the use of standard size assets often provides more capacity than required for the immediate need. Then when an unexpected new load materializes, the system of often capable of meeting the additional demand.

We realize this is the first year the Joint Prioritization Workbook Template has been used by all IOUs and as a result it may be used differently by each company. While there are differences among the IOUs, <u>we recommend that this issue be an agenda item for the next DIDF reform stakeholder webinar early in the next DIDF cycle.</u>

- There has been discussion about relative ranking of projects as opposed to ranking projects based the characteristics of the project itself. This movement of projects between tiers is apparent. San Miguel Bank 2 was a Tier 1 project in the 2020/2021 DIDF cycle and is a Tier 2 project this year. Bonita Bank 2 was also a Tier 1 project in the 2020/2021 DIDF cycle and is a Tier 2 project this year. Bids were unsuccessfully solicited for both of these projects. PG&E states it is open to changing the approach but believes currently there is insufficient data to move away from a relative ranking system. The IPE will provide comments on absolute ranking in its IPE Post DPAG Report.

5 Review of PG&E Prioritization of Candidate Deferral Projects and Pilot Selections

In this section we review CDOs that have relatively high Cost Effectiveness rankings for inclusion in Tier 1 and the selection of CDOs for the Partnership Pilot and Standard Offer Contract (SOC) Pilots.

Review of Non-Tier 1 CDOs

We believe the Cost Effectiveness metric, in general, is very important to the overall ranking process[6]. If there are insufficient funds or budget 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. For this reason, CDOs with high Cost Effectiveness rankings, and not initially recommended by PG&E for one of the DER sourcing mechanisms, were evaluated to determine if they should be moved to Tier 1.

The next 8 non-Tier 1/non-pilot CDOs with the highest Cost Effectiveness metrics rankings were evaluated to determine if they were strong candidates for Tier 1 consideration.

- Two of the CDOs, Airways Bank 3 and Fulton Bank 5, have Market Assessment flags for a large number of grid needs, which automatically places them in Tier 3. The discussion regarding the number of grid needs for Airways Bank 3 was addressed at the October 22 DPAG Webinar. PG&E stated the three grid needs threshold was established as a limit because each need required a separate DER deferral contract and greater than three grid needs resulted in additional interconnection complexity and costs. The stakeholders were asked if three grid needs threshold was a reasonable limit. There was no feedback, which was taken as acceptance.
- Two of the CDOs, Arbuckle Bank 2 and Rincon Bank 1, have fourth quartile scores in the Forecast Certainty metric and any change in the Cost Effectiveness score would not move these projects into Tier 1 because the sum of the three prioritization metrics would not be greater than zero.
- The remaining four CDOs that were reviewed were:
  - San Miguel Bank 2 with a CE ranking of 14, a FC ranking of 23, and a MA ranking of 14.
  - Bonita Bank 2 with a CE ranking of 16, a FC ranking of 23, and a MA ranking of 14.
  - Plainfield Bank 1 with a CE ranking of 17, a FC ranking of 23, and a MA ranking of 14, and
  - Blackwell Bank 1 with a CE ranking of 18, a FC ranking of 23, and a MA ranking of 14.

A sensitivity analysis was performed by increasing the cost of the individual CDOs in the prioritization workbook until the projects would be ranked in Tier 1 for the Cost Effectiveness metric - that is the CDO would be in the top quartile of the Cost Effectiveness metric. The results are:

- San Miguel Bank 2 cost would need to increase 19%,
- Bonita Bank 2 cost would need to increase 40%,
- Plainfield Bank 1 cost would need to increase 90%, and
- Blackwell Bank 1 cost would need to increase 140%.

[6] It should 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.

An additional sensitivity was performed to determine how much the project would have to increase in order to move the San Miguel CDO to the middle of Tier 1 for the Cost Effectiveness metric. To achieve this result, the cost of this CDO would need to have increase by 350%. It was noted San Miguel Bank 2 had a DIDF RFO solicitation in 2020.No cost-effective bids were received.

The Bonita Bank 2 CDO, which has good CE and MA rankings and a moderate FC ranking, was discussed at the October 22 DPAG Webinar. There was no support from the stakeholders to consider moving this CDO to Tier 1. The IPE recommended that if one of the other CDOs did not go forward, PG&E could consider the Bonita Bank 2 as a backup project.

Based on our analysis and feedback from the October 22 DPAG Webinar, no recommendations are made to change the prioritization.

PARTNERSHIP PILOT Selection

Six Candidate Deferral Opportunities are being recommended for the Partnership Pilot. They are:

- Embarcadero (SF Z) 1116
- Embarcadero (SF Z) 1118
- Coalinga No 1 Bank 2
- Rocklin 1105
- Anita 1105
- Belle Haven Bank 4

The selection of the Candidate Deferral Opportunities for the Partnership Pilot was based on the Prioritization Metrics, as well as PG&E's application of the following criteria:

1. At least one Tier 1 deferral opportunity and two Tier 2 or Tier 3 deferral opportunities must be selected.
2. Candidate Deferral Opportunities that could demonstrate Ratable Procurement (e.g., opportunities with low to moderate capacity needs that have incremental procurement goals).
3. Candidate Deferral Opportunities where Ratable Procurement could potentially address the challenge of changing distribution system needs and risk of over and under procurement.
4. Candidate Deferral Opportunities with grid needs occurring within two to five years of Pilot launch.
5. At least one deferral opportunity with a grid need forecast 4 to 5 years out to ensure the subscription period was sufficiently long in duration to test payments.
6. Clusters of deferral opportunities and planned investments.
7. Planned investments that service Disadvantaged Communities (DACs).

PG&E considered all CDOs, regardless of Tier, as eligible for the Partnership Pilot and reviewed each one based upon the criteria listed above. For example, CDOs with single grid needs and low to moderate initial grid needs were identified, as well as CDOs with high forecast uncertainty and clustering. PG&E also sought CDOs that could demonstrate ratable procurement and at least one site with multiple grid needs and one with Disadvantaged Communities.

Four of the Candidate Deferral Opportunities recommended by PG&E (Embarcadero 1116, Embarcadero 1118, Anita 1105, and Belle Haven Bank 5) are intended to provide a means to test the use of Ratable Procurement for forecasted incremental needs.

The other two Candidate Deferral Opportunities (Coalinga No 1 Bank 2 and Rocklin 1105) are intended to test the use of Ratable Procurement to address the challenge of forecast uncertainty. Both of these CDOs have low scores under the Forecast Certainty Prioritization Metric. PG&E recommends using the Partnership Pilot to test whether the use of Ratable Procurement, with Tranches updated annually via the distribution planning process, will facilitate the procurement of DERs for Candidate Deferral Opportunities with high forecast uncertainty.

Procurement Goals are the amount of capacity needed to defer the Planned Investment for no less than one year. Procurement Goals may be updated annually during the DPAG process until the entire grid need is met or the contingency date occurs, whichever happens sooner.

The DDOR includes tables for each CDO that show the Procurement Goals, Acceptance Trigger, and Procurement Caps by Tranche for each Candidate Deferral Opportunity, expressed in Megawatts (MW).

- The Procurement Goals are based on a forecasted grid need that utilizes future load forecasts to estimate capacity deficiencies.
- The Acceptance Trigger is defined as the minimum amount of capacity required to execute contracts within the Partnership Pilot framework for a given Tranche (90% of the Procurement Goal).
- The Procurement Cap is defined as the maximum allowable amount of capacity for Deployment and Reservation payments for each Tranche (120% of the Procurement Goal).

The DDOR has tables for each CDO selected for Partnership Pilot that shows Subscription Period information, which includes the Subscription Launch Date, Reservation Deadline, Subscription Duration, Contingency Dates and In-Service Dates.

- Subscription Launch Date: The date at which parties are eligible to submit reservations. The Subscription Launch Date for Tranche 1 will be the latter of the following: 30 days after the approval of the November 15, 2021, Advice Letter filing or January 18, 2022.
- The Reservation Deadline is reliant on the Contingency Date of each Candidate Deferral Opportunity. The Reservation Deadline is 60 days prior to the Contingency Date to ensure there is adequate time to: 1) review the reservation, 2) request additional information or clarify project details, and 3) award and execute a contract.
- The Subscription Duration represents the total number of days from the Subscription Launch Date to the Reservation Deadline.
- The Contingency Date is specific to the Candidate Deferral Opportunity and is based on the distribution planning process, which includes engineering and design, materials procurement, and construction.

Reservations from aggregators will be accepted from the Subscription Launch Date until either the Procurement Cap is reached, or the Contingency Date occurs, whichever occurs first. Reservations will be reviewed and verified on a first come first serve basis. Aggregators will file offer reservations for either a portion or for all the needed capacity. Once the Acceptance Trigger is achieved from one or multiple reservation offers, contracts are executable. The contract term for the first tranche is one year in duration, beginning on the In-Service Date.

The proposed Pilot Budgets supports a three-tiered payment structure with the following allocations:

- Deployment Payment: 20 percent of the Tariff Budget.
- Capacity Reservation Payment tier - 30 percent of the Tariff Budget; and
- Performance Payment tier - 50 percent of the Tariff Budget.

The DDOR has tables for each CDO that shows the Deferral Value, Deployment Budget, Reservation Budget, Performance Budget, and Tranche Budget for each of the Candidate Deferral Opportunities recommended for the Partnership Pilot, across tranches.

The Total Budget for each Candidate Deferral Opportunity is the summation of the Tranche Budgets. A Simple Pricing Method has been applied to the Partnership Pilot, whereby the Tariff Budget is set at 85 percent of the cost cap. The cost cap for each tranche is equal to the Deferral Value for the Candidate Deferral Opportunity for the term of the contract (one year). The Procurement Target for of the contracts are subject to change in sequential tranches and may vary by opportunity. All values have been discounted to the year of the In-Service Date for each tranche.

There were extensive discussions during the DPAG Webinar and follow-up DPAG Webinar about how any excess budget, if any existed, should be handled. Questions such as should the excess be returned to ratepayers, or should the excess be rolled into the next year were discussed. PG&E will consider these questions as it finalized its Partnership Pilot plans.

STANDARD OFFER CONTRACT (SOC) PILOT Selection

The SOC Pilot is a framework for DER solicitations whereby a Standard Offer Contract, based on the existing Technology-Neutral Pro Forma (TNPF), will be used to decrease the transactional costs and risks present in the current RFO process. This three-year Pilot is intended for larger scale providers of In-Front-of-Meter distributed energy resources and overlaps with the current GNA, DDOR, and DIDF RFO process.

The selection of the CDO for the SOC Pilot is based on the Prioritization Metrics and examination of the following criteria:

- At least one Tier 1 Candidate Deferral Opportunity selected.
- A single Grid Need location to defer the Candidate Deferral Opportunity, in order to facilitate a single Point of Interconnection for an In-Front-of-the-Meter (IFOM) DER solution.
- Indications that there is sufficient capacity at the location of the Grid Need for a DER to charge from the grid, so that IFOM DERs (including energy storage) may be able to charge from the location of need. PG&E notes that this assessment is only indicative, and the DER solution would still need to pursue the interconnection process.
- Earlier In-Service Dates to test the impact of the SOC pilot on the ability of DERs to meet the In-Service Date.
- Candidate Deferral Opportunities with larger Grid Needs (MW), as those needs may be most appropriate for Utility-Scale IFOM DER solutions.

Based on these selection criteria, the selected Candidate Deferral Opportunity is Vierra Bank 3 because it is a Tier 1 CDO, has a single, moderate to larger grid need and has a high Disadvantaged Community overlay.

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6 Other Items of Interest

6.1 Miscellaneous – Observations, Conclusions and Recommendations

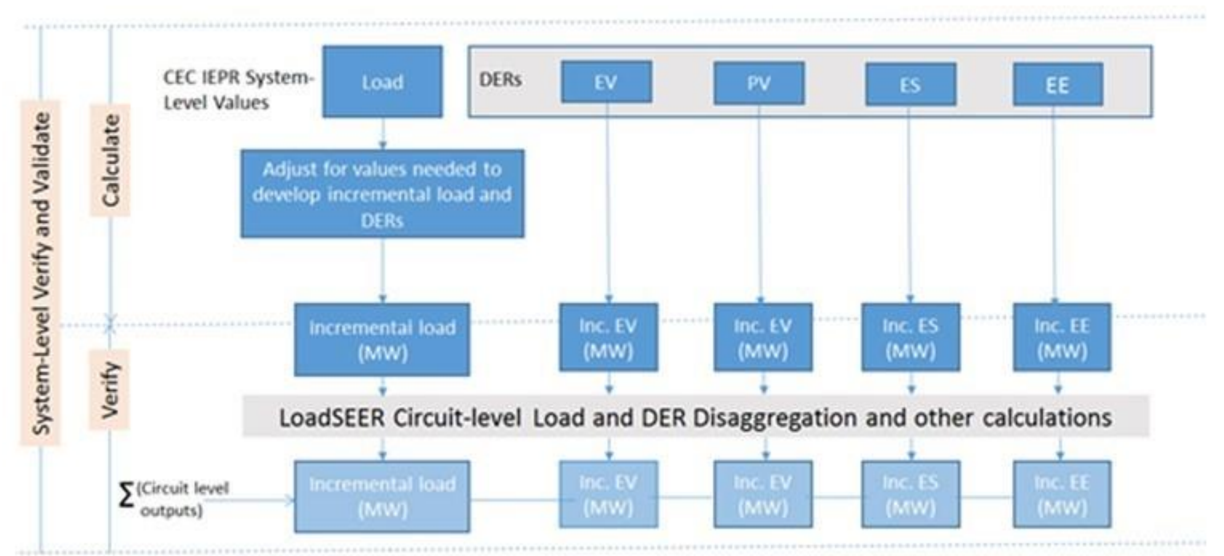
Data Provided to DPAG

As part of the development of the IPE Report that dealt with data adequacy that was completed the week prior to the DPAG meetings, the Energy Division asked the IPE to consider if the data was adequate not only for the IPE but the DPAG members. In general, we concluded that the data provided was adequate for the scope set out for the IPE. We observed that all of the information that was provided to the IPE was included with the IPE's report completed after the DPAG and therefore stakeholders would receive copies (public versions) of the data provided to the IPE. The IPE did note that DPAG members may not have that data prior to the DPAG. We recommend (to allow DPAG members to get the most out of the DPAG meeting) that the public version of the prioritization metrics spreadsheet be provided to the DPAG prior to the DPAG meeting.

7 Verification Approach and Results

The approach used to verify steps related to load forecasting and checking for circuit overloads is shown in Figure 7-1 and Figure 7-2.

Figure 7-1: System Verification

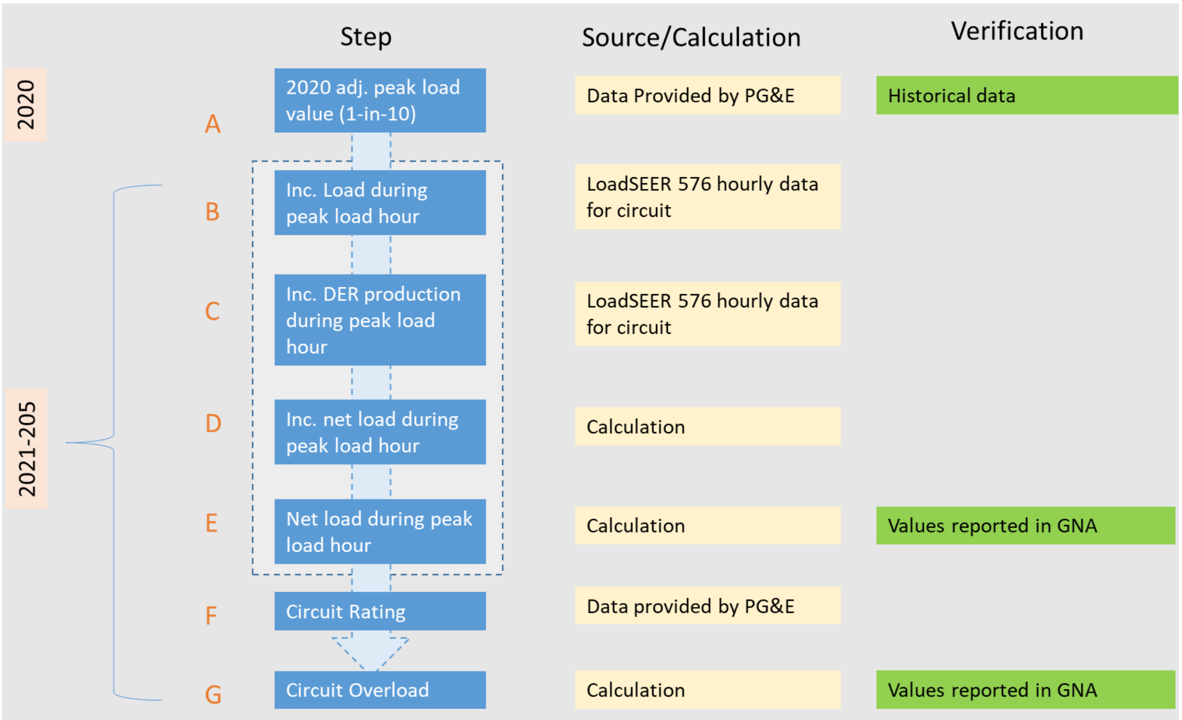


Prior to allocating the CEC IEPR System-Level forecast to distribution circuits, the system load forecast is reduced to account for:

- System-level LDEV,
- System-level Other Private generation,
- Transmission-only load, and
- New known distribution loads.

This adjusted system load is then distributed by customer class and allocated to the circuits in the LoadSEER Geographical Information System geo-spatial load forecasting program created by Integral Analytics. This program is used to model substation and feeder demand forecasts and identify grid needs using satellite imagery and proprietary data analytics to score each acre in PG&E's territory for the likelihood of increased load by customer class. This GIS model also uses historical land aerial imagery to help determine expansion trends that have occurred within specific areas and takes this information into consideration for the acre scoring analysis. The spatial forecasting model is enhanced by utilizing an energy consumption model that is weather normalized and includes economic variables. After area scores are determined, the geospatial program then allocates the CEC customer class load growth projections to 15 Load Modifying Demand Response reshapes or reduces the net load curve as opposed to Supply Resource Demand Response which is integrated into the California Independent System Operator (CAISO) energy markets. The output of the geo-spatial program is an annual PG&E peak MW growth by feeder, by customer class for the next 10 years. This growth is then uploaded into the LoadSEER Forecast Integration Tool (LoadSEER FIT) forecasting program. LoadSEER FIT uses customer-class load shapes to turn the system peak growth amount into a 576-hour load shape that can then be applied to the feeder or bank load shape. After the disaggregation of the adjusted system load, the LDEV is reallocated to circuits in LoadSEER based upon propriety algorithms and the new known loads are allocated based upon new application information. The Other Private generation and Transmission-only loads are not disaggregated to individual feeders.

Figure 7-2: Circuit Level Verification



The review includes both 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 DER growth forecasts for the planning period.
- This review of CED IEPR data adjustments for such items as transmission customer loads and known new distribution customer loads.
- It also includes a check of the output results of the disaggregation of load and DERs to confirm 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.

7.1 Processes to Develop System Level Forecasts at Circuit Level

7.1.1 Collect 2019 Actual Circuit Loading, Normalize and Adjust for Extreme Weather – Steps 1 and 8

Monthly peak loads are routinely obtained from SCADA or manual reads and entered into LoadSEER. To determine peak loads for the load forecast, peak load values are obtained from LoadSEER for the months of June through September. The peak load value for the summer months is checked by the Distribution Planning Engineer to ensure it was not associated with a system operating abnormality and is then entered into LoadSEER for 1-in-2 and 1-in-10 load forecasts. If a circuit is identified as subject to temperature variations, LoadSEER adjusts the actual peak load according to the temperature at the time of the peak and generates a 1-in-2 and a 1-in-10 load forecast based on this new adjusted peak load. The actual number of circuits that are identified as temperature sensitive is not known, however discussions with PG&E indicate less than 25% of the circuits are temperature sensitive. If the circuit is not identified as temperature sensitive, the starting peak load is not adjusted and the forecast starting point for the 1-in-2 and 1-in-10 forecasts in LoadSEER is the most recent historic peak load. Ten circuits were selected for verification. Table: Data for Circuit Net Load Verification, presents the data collected and reviewed. Five circuits were treated as temperature sensitive in the LoadSEER. For these temperature sensitive circuits, the actual peak loads were adjusted for the 1-in-2 and 1-in-10 forecasts as identified in PG&E procedure.

Table 7-1: Data for Circuit Net Load Verification

Feeder Name	Weather sensitive? (Was temperature selected as a regression variable?)	Water sensitive? (Was a water variable selected as a regression variable?)	Did EDPI data require correction?	2021 Summer Rating from EDPI (MW)	2020 Peak Average Amps from EDPI	2020 Peak Amps in LoadSEER	If EDPI is different from LoadSEER, why?	2020 (Amps) Corporate 1-in-2 Temp Adjusted Forecast	2021 (Amps) - Final 1-in-2	2021 (Amps) - Final 1-in-10
Llagas 2101	Yes	No	No	21.12	434	434	n/a	417	459	503
Edenvale	No	No	Yes, switching	20.04	565	529	Yes, temp load transfer	n/a	545	606
Wyandotte 11	Yes	Yes	No	12.38	466	466	n/a	455	451	472
Lakewood 110	Yes	No	Yes, generatior	10.87	419	421	Solar generation added to pe	407	407	464
Saratoga 1107	Yes	No	No	11.69	530	530	n/a	481	474	513
Yosemite 0402	No	No	Yes, no EDPI da	2.71	n/a	150	No SCADA available	n/a	150	152
Rincon 1101	Yes	No	No	11.45	511	511	n/a	429	422	443
Meridian 1102	No	Yes	Yes, switching	6.2	255	206	Yes, temp load transfer	n/a	206	225
Figarden 2102	No	No	Yes, switching	21.44	568	534	Yes, temp load transfer	n/a	587	616
Anita 1101	No	Yes	No	12.32	207	207	n/a	n/a	210	239

7.1.2 Determine Load and DER Annual Growth on System Level - Step 2

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 below in Figure 7-3.

Figure 7-3: Peak Forecast Based on CED 2019 Forecast

PGE TAC Peak and Energy Forecasts: CEDU 2018 Forecast, Mid Baseline-Mid AAEE/AAPV															
Coincident Peak 1 in 2 (MW)			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	21559	21651	22028	22387	22794	23126	23452	23801	24104	24399	24662	24923	25176
2	*Line 2 of Mid-Baseline Forecast*	System-level EV forecast (will be disaggregated at feeder level)	86	115	144	172	203	238	267	288	311	337	351	373	395
3	*Line 9 of Mid-Baseline Forecast*	System-level Other Private Generation (will not be disaggregrated at feeder level)	1159	1163	1165	1167	1169	1170	1171	1171	1170	1170	1170	1170	1170
4		Transmission-Only Loads	2230	2240	2250	2260	2270	2280	2290	2300	2310	2320	2330	2340	2350
5	*line 1 minus line 2 minus line 3 minus line 4*	Total Modified Distribution System Load	18084	18133	18470	18789	19152	19438	19725	20042	20312	20572	20810	21041	21262
6	*(YearX+1)-(Year X)*	Annual incremental MW growth of distribution system load at peak			337	319	363	286	287	317	270	260	238	231	221
7															
8	CUSTOMER CLASS CONTRIBUTION TO INCREMENTAL PEAK LOAD GROWTH (MW) BY YEAR														
9	Residential	40%			135	128	145	114	115	127	108	104	95	92	88
10	Commercial	12%			40	38	44	34	34	38	32	31	29	28	27
11	Industrial	33%			111	105	120	94	95	105	89	86	79	76	73
12	Agricultural	15%			51	48	54	43	43	48	40	39	36	35	33
13															
14	KNOWN CUSTOMER CLASS PEAK LOAD GROWTH (MW) BY YEAR*														
15	Known Commercial Loads (minimum 5 MW assumed known in any year), 2020, 2021, and 2022 applications averaged due to timing uncertainty				96	96	96	12	5	5	5	5	5	5	5
16	Known Industrial Loads (minimum 40 MW assumed known in any year), 2020, 2021, and 2022 applications averaged due to timing uncertainty				93	93	93	40	40	40	40	40	40	40	40
SS	Known Agricultural Loads (minimum 10 MW assumed known in any year), 2020, 2021, and 2022 applications averaged due to timing uncertainty				57	57	57	10	10	10	10	10	10	10	10
18															
19	REMAINING ANNUAL INCREMENTAL GROWTH BY CUSTOMER CLASS THAT SHOULD BE ALLOCATED TO FEEDERS (CORPORATE FORECAST)														
20	*equals Line 9 (known adjustments not applied in LoadSEER)*	RESIDENTIAL			135	128	145	114	115	127	108	104	95	92	88
21	*equals Line 10 minus Line 15, 0 if negative, total must match Line 10*	COMMERCIAL			0	0	0	5	5	5	5	5	5	5	5
22	*equals Line 11 minus Line 16, 0 if negative, total must match Line 11*	INDUSTRIAL			18	12	27	54	55	65	49	46	39	36	33
23	*equals Line 12 minus Line 17, 0 if negative, total must match Line 12*	AGRICULTURAL			0	0	0	31	31	33	28	27	24	23	21
		TOTAL REMAINING INCREMENTAL GROWTH			153	140	172	205	206	229	190	182	163	156	147
		2020 TO 2029 GROWTH			1796										
	*Note that application data was pulled 4 months prior to final forecasts, so numbers may not exactly match known load applications at time the forecasts were finalized														

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

7.1.3 Disaggregate Load and DER Annual Growth to the Circuit Level – Step 3

PG&E uses the results of the LoadSEER software to disaggregate system-level load and DER forecasts to each circuit. Table 7-2 shows the system-level load forecasts by customer class derived from the CEC IEPR (verified in Step 2) that are an input to this step. Table 7-3 shows the aggregated circuit-level loads by customer class. It can be observed that the load added by customer class by the end of the study period, i.e., year 2030 is the same between the two, but the trajectory is different.

Table 7-2: System-level load forecasts derived from the CEC IEPR

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
RESIDENTIAL	0	0	27	57	87	117	147	177	208	239
COMMERCIAL	0	0	7	15	23	33	43	53	64	75
INDUSTRIAL	0	0	21	46	71	96	121	146	173	200
AGRICULTURAL	0	0	10	20	30	41	52	63	78	93
TOTAL	0	0	65	138	211	287	363	439	523	607

Table 7-3: Aggregated circuit-level load forecasts derived from LoadSEER results

RESIDENTIAL	20	39	73	109	144	170	187	206	223	239
COMMERCIAL	7	14	22	30	38	46	55	63	69	75
INDUSTRIAL	18	35	63	94	114	131	148	166	183	200
AGRICULTURAL	9	18	29	38	48	58	67	75	84	93
TOTAL	54	106	187	271	344	404	457	510	559	607

Similarly, PG&E disaggregates system-level growth forecasts down to the circuit level for the following four DERs: Additional Achievable Energy efficiency (AAEE), Photovoltaics (PV), Energy Storage (ES), and Electric Vehicles (EV). The IPE verified that the sum of the disaggregated circuit-level forecasts matches with the system-level forecasts provided by the CEC.

Table 7-4 shows a comparison of the disaggregated circuit-level forecasts for AAEE with the system-level forecasts for the Mid-Low case, which is at the WECC busbar level. It can be seen from the table that the two values match very closely.

Table 7-4: AAEE forecast verification at the circuit level

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
CEC System-level Forecast (MW)	43.8	44.5	48.8	6.7	40.2	37.9	37.9	33.3	44.6	37.3
Sum of Circuit-level Forecast (MW)	43.7	44.4	48.7	6.6	40.1	37.7	37.8	33.3	44.4	37.2

PG&E disaggregates the residential light duty electric vehicle (LDEV) stock forecast provided by the CEC at the zonal level (Zones 1-6) to the circuit-level. PG&E does not use the commercial LDEV stock forecast from CEC, rather uses known load EV additions in place of this. PG&E also does not model MHDEV and electric buses as explicit loads in the GNA. Table 7-5 below compares the zonal stock forecast provided by CEC with the disaggregated circuit-level stock forecasts. It can be seen from the table that the two values match very closely. The LDEV stock is then converted to load using a standard EV profile.

Table 7-5: Residential LDEV forecast verification at the circuit level

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
CEC System-level Forecast (cars)	118,331	118,266	123,001	106,040	105,545	83,102	79,627	82,869	86,926	94,817
Sum of Circuit-level Forecast (cars)	118,248	118,195	122,997	106,043	105,813	82,998	78,870	82,006	85,780	93,939

PG&E disaggregates the residential and commercial PV solar forecast provided by the CEC at the zonal level (Zones 1-6) to the circuit-level. The IPE verified that the sum of the disaggregated circuit-level forecasts matches with the system-level forecasts provided by the CEC. It can be seen from Table 7-6 that the two values match exactly.

Table 7-6: Residential and Commercial PV forecast verification at the circuit level

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
	Residential PV Solar									
CEC System-level Forecast (MW)	558	374	264	209	186	179	177	176	174	172
Sum of Circuit-level Forecast (MW)	558	374	264	209	186	179	177	176	174	172
	Commercial PV Solar									
CEC System-level Forecast (MW)	180	186	192	199	206	214	222	231	241	250
Sum of Circuit-level Forecast (MW)	180	186	192	199	206	214	222	231	241	250

Similar to PV, PG&E disaggregates the residential and commercial energy storage (ES) forecast provided by the CEC at the zonal level (Zones 1-6) to the circuit-level. It can be seen from Table 7-7 that the two values match exactly.

Table 7-7: Residential and Commercial ES forecast verification at the circuit level

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
	Residential Energy Storage									
CEC System-level Forecast (MW)	32	35	37	38	39	40	41	42	43	44
Sum of Circuit-level Forecast (MW)	32	35	37	38	39	40	41	42	43	44
	Commercial Energy Storage									
CEC System-level Forecast (MW)	9	9	9	9	9	9	9	9	9	9
Sum of Circuit-level Forecast (MW)	9	9	9	9	9	9	9	9	9	9

7.1.4 Add Incremental Load Growth Projects to Circuit Level Forecasts (those loads not in CEC forecast) – Step 4

PG&E accepts the CEC ten-year forecast and does not assume there are other loads that will connect to the PG&E distribution system not included in that forecast. However, they do identify specific loads they expect with a high degree of confidence will be connected on specific circuits because the developer has submitted an application for service. These make up the “new known distribution loads” adjustment made to the CEC annual system load growth forecast. After the adjusted (remaining) system load is allocated to the circuits, these new known distribution loads are added to their specific circuits.

Typical new known distribution loads include loads such as, industrial, commercial, agricultural, and residential projects, cannabis growers, and electric vehicle DC charging stations. This information is obtained from service planning applications for new loads.

As seen in Table 7-8, there is significant expected load growth in all classes of load including EV charging and cannabis growth. The known loads calculated from the interconnection requests don't match with the known loads used in Step 2. This is because PG&E continuously updates the list of known loads and list used for Table 7-8, is more current than the list of known loads used in Step 2.

Table 7-8: MW of New Known Distribution Load by year

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
EV	152.3	105.2	11.7	5.8	4.2	1.8		1.9	0.0	0.0	283.0
New Agricultural	76.3	19.9	5.0	2.3	3.1						106.6
New Cannabis	85.6	66.9	33.8	10.7				0.3			197.2
New Commercial	211.2	130.9	61.7	28.0	20.8	8.9	4.6	9.1	1.7	1.6	477.5
New Industrial	222.7	119.4	70.8	17.3	11.5	7.8	6.0	2.1	0.7		458.4
New Residential	100.5	66.1	19.9	8.7	5.0	1.5	1.1	0.8			203.8

As shown in Table 7-9, the in-service dates for most of the known loads are in first two years of the planning window.

Table 7-9: Count of New Known Distribution Load by Year

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total
EV	218	109	21	11	5	3		2	1	1	371
New Agricultural	348	28	15	16	1						408
New Cannabis	115	49	22	21				1			208
New Commercial	312	136	41	20	13	6	3	3	1	1	536
New Industrial	207	79	33	15	9	5	3	1	1		353
New Residential	259	148	57	18	13	4	1	1			501

7.1.5 Convert Peak Growth to 8760 Profile, Determine Net Load and Peak Load – Steps 5, 6, and 7

PG&E uses the circuit-level peak load growth forecast (also called Corporate Forecast) by customer class (verified in Step 3) and 576-hourly profiles from LoadSEER for each customer class to develop the Peak load growth 576 hourly profile for each feeder for each forecast year. This is done using LoadSEER which calculates the 576-hourly load growth profiles at different percentile levels such as P5, P25, P75, and P95. If there are any new known loads assigned to a feeder, these loads are also modeled using standard 576-hourly load profiles for each customer class.

Similarly, PG&E uses the circuit-level DER growth forecast by customer class (if applicable) and standard 576-hourly profile for each DER to develop the DER growth 576 hourly profile for each feeder for each forecast year. The load growth and DER profiles are added to the base load profile to obtain the net load profile for each year. The peak of this net load profile is compared against the rating of the feeder to determine if there are overloads.

In this step, the IPE obtained the 576-hourly load profiles for base load, Corporate and known load growth, and DER growth from LoadSEER for several circuits. These feeders were chosen based on the following criteria:

a. One or more feeders that have sensitivity to temperature and one or more that have sensitivity to water allocation,

b. One or more feeders that have known load (Residential or Commercial) additions,

c. One or more feeders that have identified needs that are solved using load transfer,

d. One or more feeders that have identified needs that are solved with a planned project,

e. One or more feeders with needs that result in Candidate Deferral Opportunity (CDO) project,

f. One or more feeders with known DCFC addition.

The IPE also obtained standard load profiles for new loads by customer class and various DERs by customer class, as applicable. We then used the peak load and DER forecast at the feeder level (verified in Step 3) and the standard profiles to develop our own 576 hourly profiles and compared it with those from LoadSEER. This was done to verify the annual peak loads are being calculated based on the information provided by PG&E.

While this verification was performed on a number of feeders, only the results for Figarden 2102 circuit are presented in this section. This feeder has load growth due to known commercial load addition, as well as growth due to PV, energy storage, EV, and energy efficiency. Figure 7-4 shows the load profile for a day in January 2021 and 2030 for commercial solar for the Figarden 2012 circuit from LoadSEER. Figure 7-5 shows the same information as calculated by the IPE. As observed, the commercial solar profile calculated by the IPE matches exactly with what was produced by LoadSEER. Similarly, Figure 7-6 and Figure 7-7show a comparison of the load profiles for residential LDEVs, and Figure 7-8 and Figure 7-9 a comparison of energy storage. Again, the figures produced by the IPE match exactly with those from LoadSEER. As mentioned earlier, this circuit also has a known commercial load addition of 2.2 MW. Figure 7-10 and Figure 7-11 show a comparison of the 576-hourly load profiles for new commercial load in 2021 as produced by LoadSEER and as calculated by the IPE. A comparison of the 576-hourly load profile is made since the loads vary by the month and day (weekday vs. weekend).

Figure 7-4: Load profile for Commercial PV for the Figarden 2102 circuit from LoadSEER

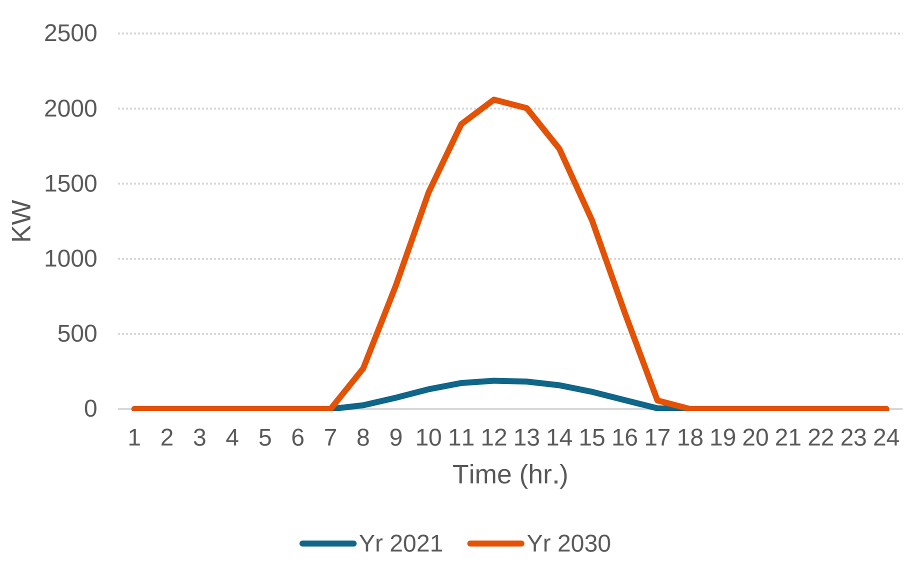


Figure 7-5: Load profile for Commercial PV for the Figarden 2102 circuit calculated by the IPE

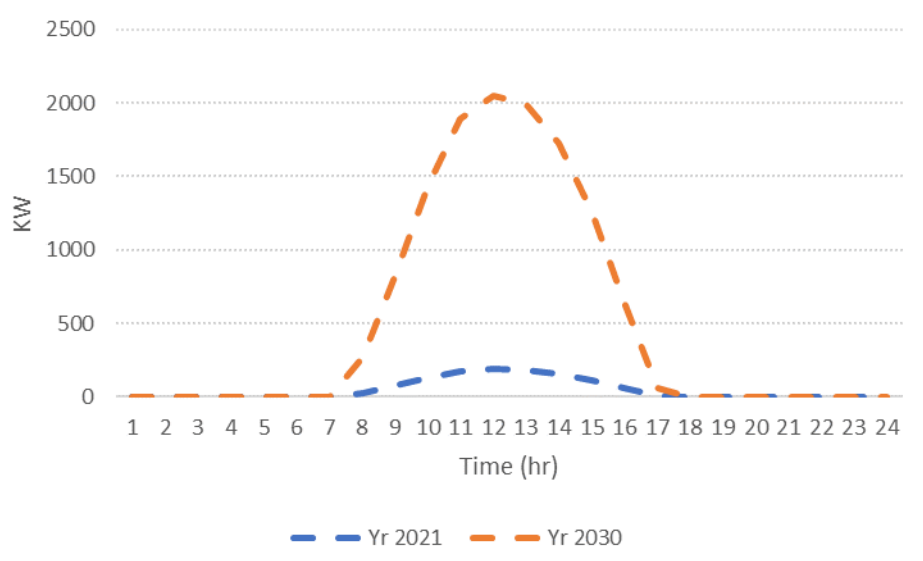


Figure 7-6: Load profile for Residential LDEV for the Figarden 2102 circuit from LoadSEER

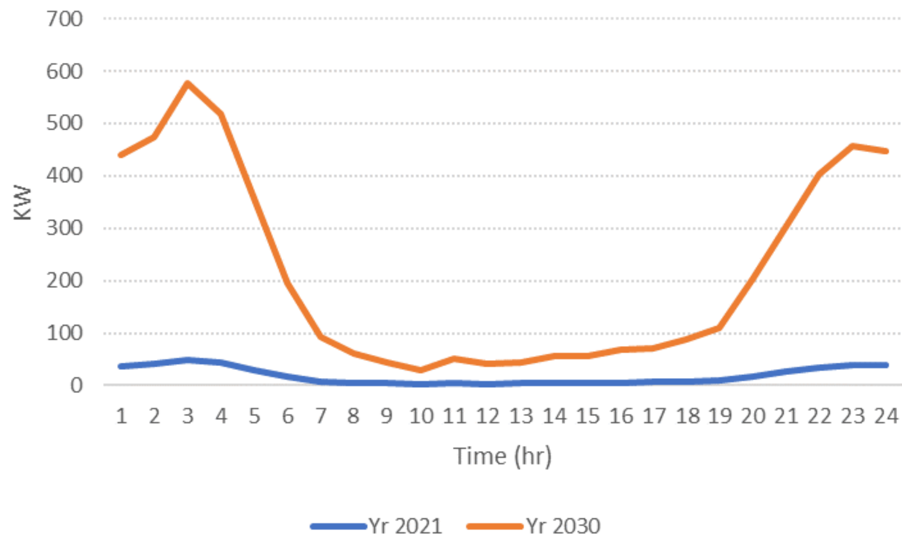


Figure 7-7: Load profile for Residential LDEV for the Figarden 2102 circuit calculated by the IPE

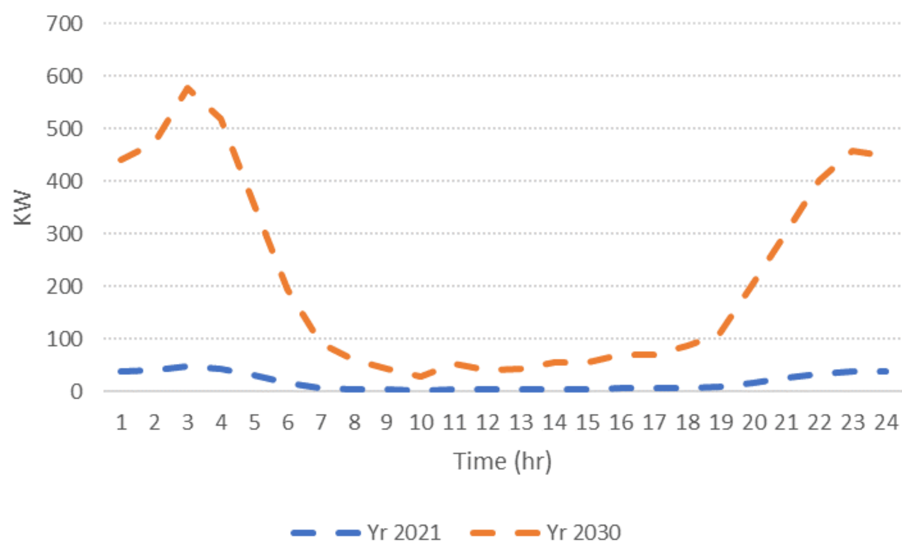


Figure 7-8: Load profile for Energy Storage (Charging) for the Figarden 2102 circuit from LoadSEER

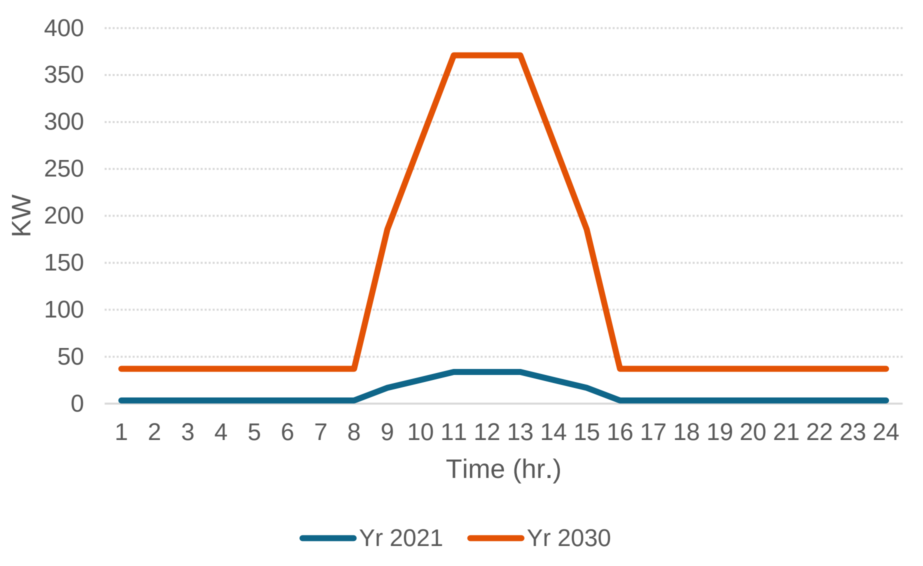


Figure 7-9: Load profile for Energy Storage (charging) for the Figarden 2102 circuit calculated by the IPE

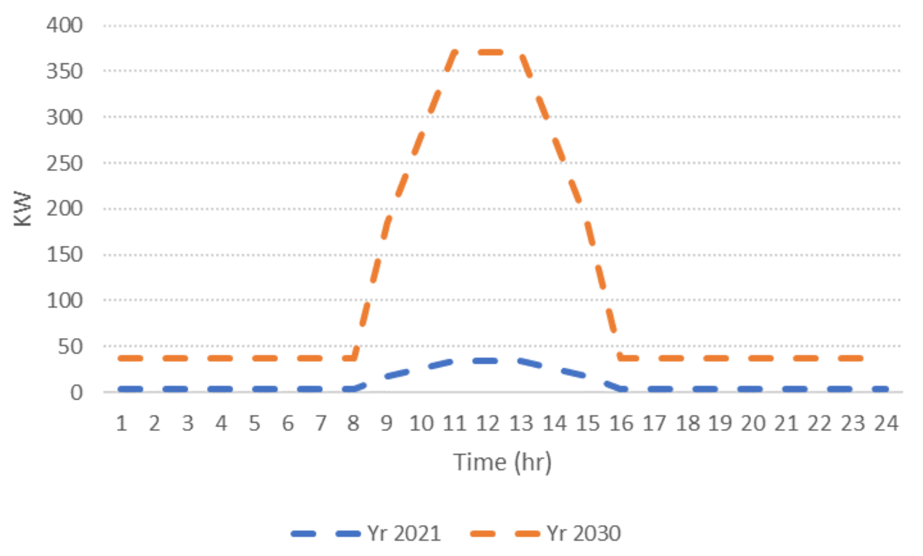


Figure 7-10: Load profile for new commercial load for the Figarden 2102 circuit from LoadSEER

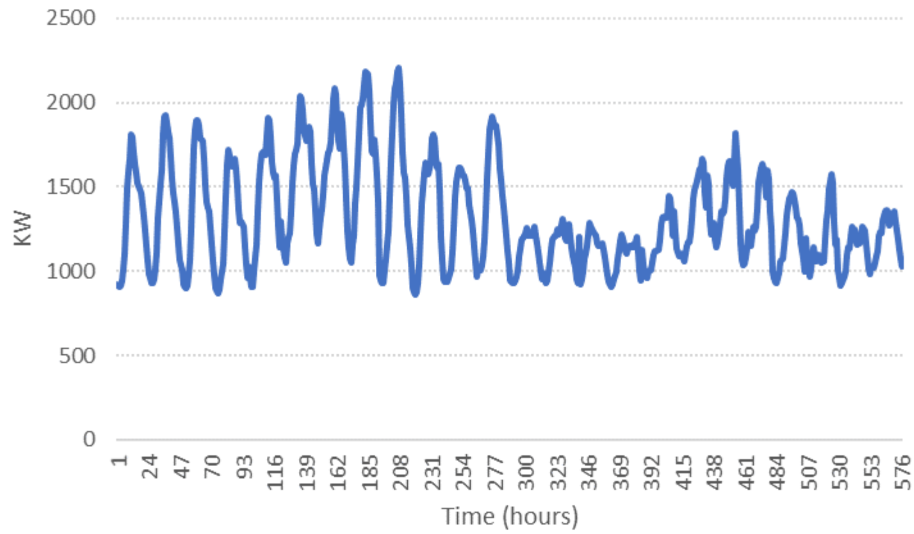
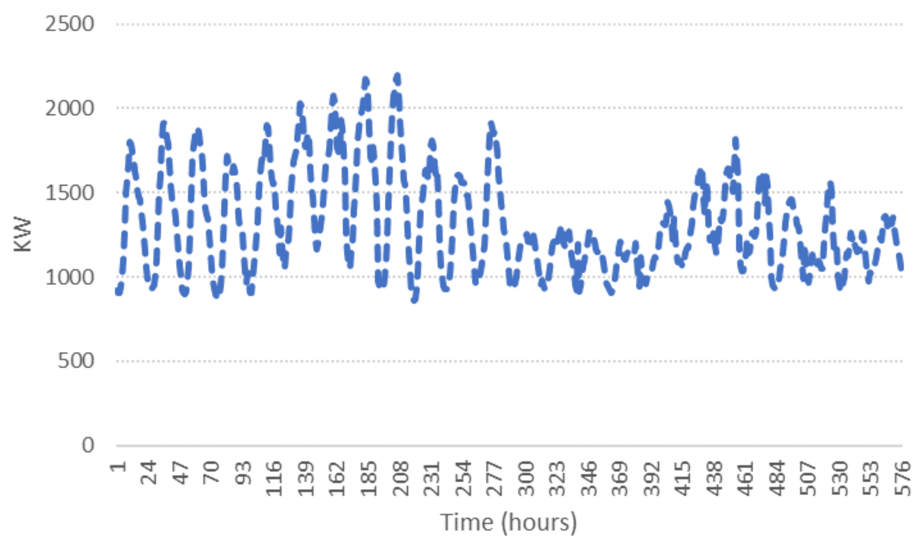


Figure 7-11: Load profile for new commercial load for the Figarden 2102 circuit calculated by the IPE



Since Figarden 2102 circuit does not have any loads due DCFC fast charger, local delivery fleet, or transit agency, other circuits were chosen for this purpose. Figure 7-12 through Figure 7-14 show the EV charging profile for a DCFC, a local delivery fleet and a transit authority from feeders Vineyard 2104, Deepwater 1108 and San Luis Obispo 1108 respectively.

Figure 7-12: 24-hour DCFC charger profile

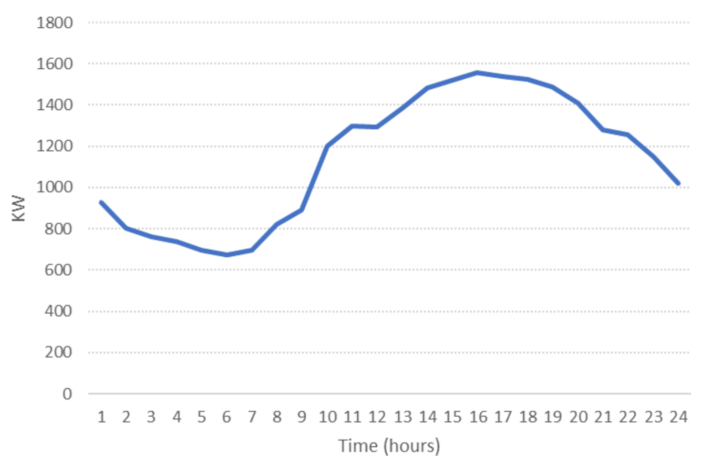


Figure 7-13: 24-hour local delivery fleet charging profile

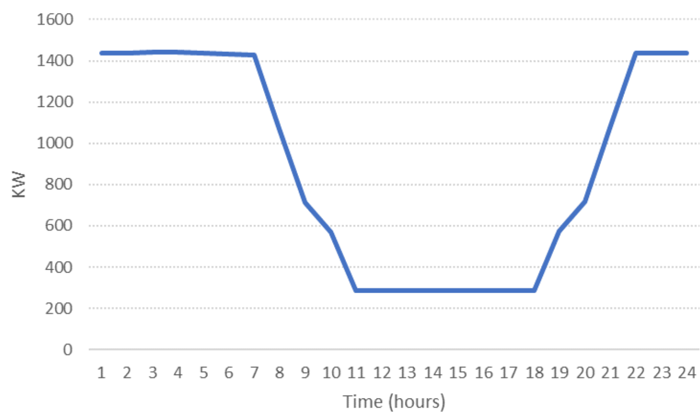
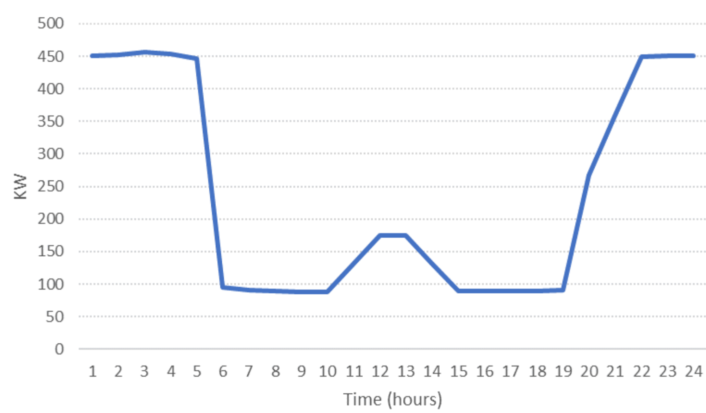


Figure 7-14: 24-hour transit authority charging profile



By using the process described above, the IPE verified the load profiles developed in LoadSEER for load and DER growth. Since the net load is the sum of the base load profile (i.e., existing load) and the growth due to load and DERs, it is reasonable to conclude the net load profile has also been verified by the IPE.

As mentioned earlier, the peak load used for determining circuit and bank overloads is obtained from the peak of the net load profile. Using the 576-hourly data provided by PG&E, the IPE determined the peak load as a percentage of the bank/circuit's rating and compared it against what was used in the GNA. Table 7-10 shows the peak load as a percentage of the rate as calculated by the IPE. These values exactly match with the loadings reported in the GNA for these circuits[7].

Table 7-10: Peak load as a percentage of rating for select circuits as calculated by the IPE

	Figarden 2102	Anita 1101	Edenvale 2109	Lakewood 1104	Meridian 1102	Llagas 2101
2021	107%	46%	112%	92%	75%	88%
2022	110%	47%	104%	92%	75%	88%
2023	112%	48%	104%	93%	75%	88%
2024	111%	48%	104%	94%	74%	89%
2025	110%	49%	105%	94%	74%	89%
2026	110%	49%	105%	95%	74%	89%
2027	109%	50%	105%	95%	74%	89%
2028	109%	51%	105%	96%	74%	89%
2029	109%	51%	105%	97%	73%	89%
2030	109%	52%	105%	97%	73%	89%

[7] The GNA tables only have the loadings for the first 5 years (2021-2025).

7.2 Processes to Determine Circuit Needs and Develop GNA

7.2.1 Initial Comparison to Equipment Ratings, Evaluate No Cost Solutions and Comparison to Equipment Ratings after No Cost Solutions – Steps 9, 10, and 11

Loading After Free Transfers

Facility ratings for existing banks and feeders are available in GNA Appendix E: GNA Results - Bank & Feeder Capacity Needs. However, the load data prior to the application of free transfers are not provided in either the GNA or DDOR reports. Therefore, a comparison of equipment rating to facility loading after the application of free transfers was performed for the feeders and banks reviewed in Steps 5-7. Table 7-11: Comparison of Facility Ratings and 2021 Load Forecasts After Free Transfers, shows the facility ratings and associated 2021 forecast loads. It is noted six facilities are overloaded.

Table 7-11: Comparison of Facility Ratings and 2021 Load Forecasts After Free Transfers

Feeder/Bank	GNA Data		Loading from Profiles (Steps 5-7)	Loading Status
	Capability	Loading		
Bonita 1102	9.62	5.59	5.59	OK
Bonita Bank 1	15.73	15.35	15.35	OK
Concord 401	2.38	2.01	2.01	OK
Concord 402	2.38	2.23	2.23	OK
Figarden 2102	20.15	21.58	21.58	Overloaded
Green Valley Bank 3	29.7	35.91	35.91	Overloaded
Manteca Bank 7	29.7	29.38	29.38	OK
Ripon 1704	14.42	17.15	17.15	Overloaded
Ripon Bank 2	27.7	27.96	27.96	Overloaded
Storey 1106	12.19	13	13	Overloaded
Belle Haven Bank 3	15.8	15.98	15.98	Overloaded

Load Transfers

Evaluating potential load transfers involves both LoadSEER and the CYME load flow program. The LoadSEER program provides bank and feeder loading and capacity information, while the CYME load flow program determines loading between sectionalize devices and identifies any voltage or conductor loading problems. Loads to be transferred between sectionalizing devices are obtained by the Distribution Planning Engineer from the CYME load flow program and entered into LoadSEER for new bank and feeder loading results. The transfers are also reflected in CYME (new loading and circuit reconfiguration) to ensure no line section voltage or capacity problems result.

PG&E demonstrated a no cost load solution from the Concord 401 circuit to the Concord 402 circuit. This transfer is being made to reduce the 0.235 MW overload on the Concord 401 circuit. The results of this transfer are shown in Table 7-12.

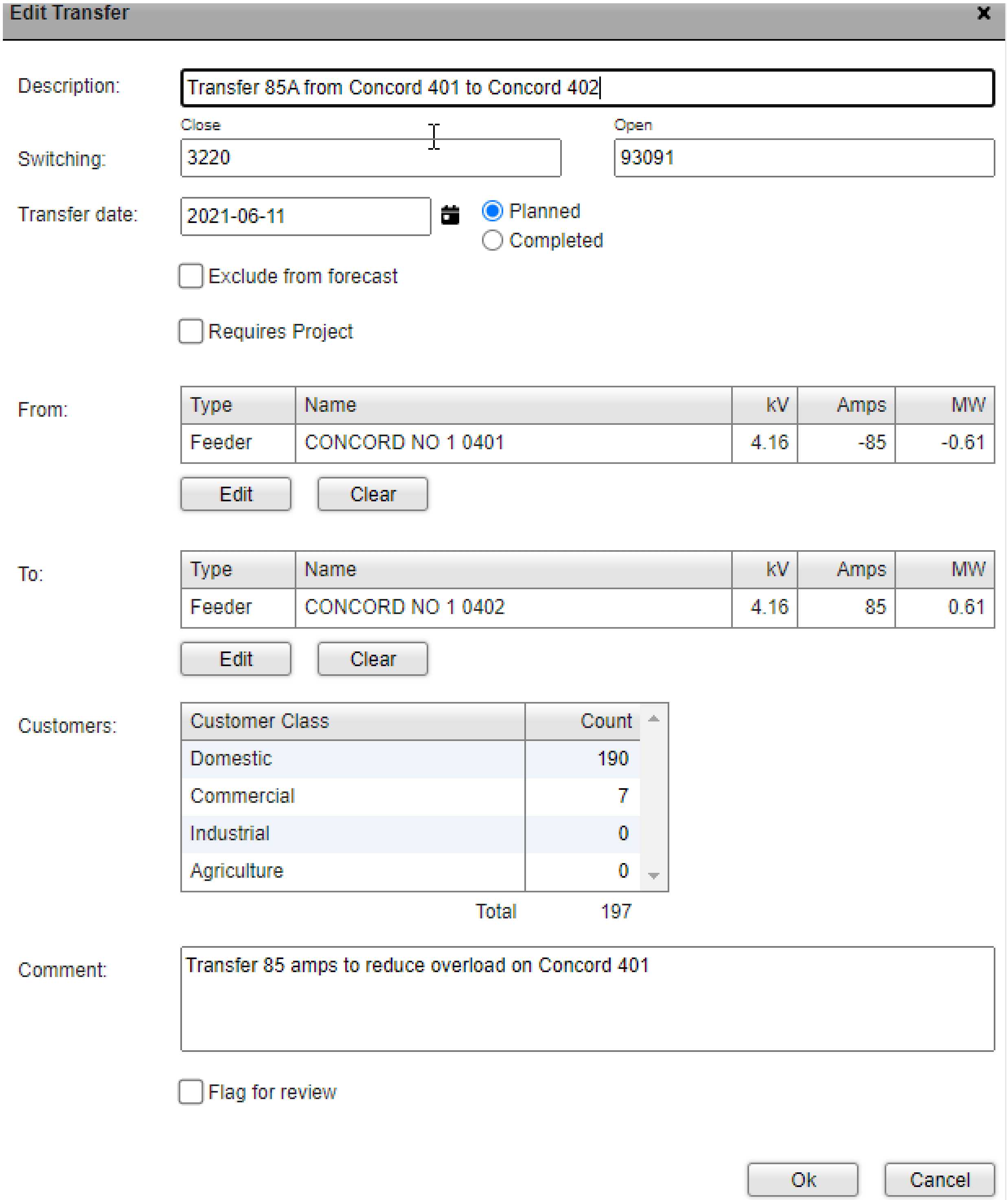
Table 7-12: Free Load Transfer from Concord 401 to Concord 402

Feeder	Rating (MW)	Before Free Transfer Loading (MW)	After Free Transfer Loading (MW)
Concord 401	2.38	2.615	2.009
Concord 402	2.38	1.627	2.233
Total		4.242	4.242

The load between sectionalizing devices on the Concord 401 circuit is obtained from CYME. This load is removed from the Concord 401 circuit and added to the Concord 402 circuit in LoadSEER to obtain final loading results. In addition, the circuit arrangements or configurations are changed in CYME to account for the transfer and new power flow analyses are completed to ensure no overloads or voltage violation result from this load transfer.

In this case, the need to reduce load on Concord 401 circuit is accomplished by transferring 0.61 MW (85 amps) to the Concord 402 circuit. As can be seen from Figure 7-15, the switching operation required and the loading before and after the transfer can be seen for both circuits.

Figure 7-15: Transfer 0.61 MW from Concord 401 to 402 Circuit



Loading after Planned Investments

In this step, a review was done to confirm planned investments were identified to mitigate the overloaded conditions on the six banks and feeders identified earlier in Table 7-6. The planned investments were obtained from DDDOR Appendix A: Planned Investments. Review of this Appendix found Planned Investments for each of the overloaded conditions as show below in Table 7-13.

Table 7-13: Planned Investments for Overloaded Facilities

Feeder/Bank	GNA Data		Loading from Profiles (Steps 5-7)	Loading Status	Planned Investments from DDOR Appendix A: Planned Investments
	Capability	Loading			
Bonita 1102	9.62	5.59	5.59	OK	N/A
Bonita Bank 1	15.73	15.35	15.35	OK	N/A
Concord 401	2.38	2.01	2.01	OK	N/A
Concord 402	2.38	2.23	2.23	OK	N/A
Figarden 2102	20.15	21.58	21.58	Overloaded	Install Figarden 2114 Feeder
Green Valley Bank 3	29.7	35.91	35.91	Overloaded	Green Valley - Replace Bank 3
Manteca Bank 7	29.7	29.38	29.38	OK	N/A
Ripon 1704	14.42	17.15	17.15	Overloaded	Install 1-17kV feeder - Ripon Bank 1
Ripon Bank 2	27.7	27.96	27.96	Overloaded	Rincon - Install Feeder 1105
Storey 1106	12.19	13	13	Overloaded	Install 1-12 kV feeder - Storey 1103 on Bank 1 and replace bank
Belle Haven Bank 3	15.8	15.98	15.98	Overloaded	Belle Haven - Replace Bank 4 w/ 30MVA and Inst BH 1109 Fdr

7.2.2 Compile GNA Tables Showing Need and Timing – Step 12

A review was done to compare the drivers, need date and deficiencies in GNA, Appendix E: GNA Results - Bank & Feeder Capacity Needs, with 10 CDOs identified in DDOR. The results are shown in Table 7-14, Review of Drivers and Deficiencies of Potential Candidate Deferral Opportunities. In most cases the DDOR deficiency is greater than the GNA deficiency. This is because GNA uses a five-year planning horizon while DDOR uses a ten year planning horizon. There are four exceptions in this table. For the Lockeford Bank 1 and Montague Bank 2 CDOs, the differences between the GNA and DDOR deficiencies are not a result of a normal grid capacity need but rather the result of an emergency loss of a substation bank. The Rob Roy 2105 is a resiliency issue resulting from having more than 6,000 customers on a feeder. Finally, the peak load for the Willow Pass Bank 3 CDO occurs in the first five years of the planning horizon.

Table 7-14: Review of Drivers and Deficiencies of Potential Candidate Deferral Opportunities

Candidate Deferral Opportunity	Tier	Drivers	GNA Anticipated Need Date*	DDOR In-Service Date	GNA Deficiency (MW)	DDOR Deficiency (MW)
Embarcadero 1116	1	Embarcadero 1116	2024	2026	0.07	0.3
Mormon Bank 2	1	Mormon 1102, East Stockton Bank 3	2021	2025	0.75	1.1
Rocklin 1105	1	Del Mar Bank 2	2022	2025	0.34	0.7
Anita 1105	2	Nord Bank 1, Nord Bank 2, Anita Bank 1	2021-2025	2024	2.8	3.8
Green Valley Bank 3	2	Green Valley Bank 3	2021	2024	5.55	6.2
Airways Bank 3	3	Airways 1107 (capacity and voltage), Airways Bank 2, Airways 1102, Coppermine 1104,	2021-2024	2024	4.09	4.5
Lockeford Bank 1	3	Lockeford Bank 4 (capacity and resiliency), Lodi Bank 2	2021-2023	2025	0.92	19.5
Montague Bank 2	3	Montague Bank 3	None	2025	0	7.6
Rob Roy 2105	3	Rob Roy 2105	None	2024	0	4.6
Willow Pass Bank 1	3	Willow Pass Bank 3	2021	2024	10.19	10.2

* Anticipated Need dates may have a range due to multiple needs

7.3 Processes to Develop Planned Investments and Costs

7.3.1 Develop Recommended Solution – Step 13

PG&E has a design criterion, "*Guide for Planning Area Distribution Facilities*" dated 8/15/18 which has been revised to include LoadSEER forecasting, DER inclusion, and GNA and DDOR requirements and timeline. This guideline provides the distribution planners with the explanation and rational for distribution system and component planning, capability of assets, load forecasting, and normal and emergency planning.

The development of two potential CODs were demonstrated – one for a feeder, Anita 1105 and one for a bank, Mormon Bank 2. In each instance the approach to developing a solution was consistent with the "*Guide for Planning Area Distribution Facilities*".

7.3.1.1 Anita 1105 (Tier 2)

The Anita 1105 CDO meets two immediate needs, Nord Bank 1 and Nord Bank 2, and one longer term need, Anita Bank 1.

When the Nord Bank overloads were initially identified, normal transfers to adjacent substations were investigated but did not mitigate the overloads. The initial solution was to replace one of the Nord banks. As the planning cycle progressed, an overload at Anita Sub in 2025 was found. Anita and Nord Substations have weak distribution ties and are not normally considered for permanent load transfers. The alternative of installing a new feeder at Anita Sub and reinforcing the distribution ties between the two substation was developed. As a result of this CDO, over 2 MW of load will be transferred to Anita from Nord and relieve the Nord Sub overload condition. The estimated cost of this work is approximately $2.5 M while the cost to replace one of the Nord banks is approximately $10 M.

7.3.1.2 Mormon Bank 2 (Tier 1)

The Mormon Bank 2 CDO also meets two needs, overloads of both the Mormon 1102 circuit and the East Stockton Bank 3.

The Mormon 1102 circuits serves an agricultural area with a large pumping load. This area is also temperature sensitive. The forecast from LoadSEER indicated an overload in 2021. Transfers to adjacent stations are not available.

The 2021 forecast for East Stockton Bank 3 also projected an overload in 2021. This overload is a result of a growing industrial area served by this bank. PG&E has historically transferred load from Mormon Sub to East Stockton Bank 3, but because of the industrial load growth, this capability is no longer available.

Transfers were considered to other stations, but there is no excess capability available.

The solution currently proposed is the Mormon Bank 2 CDO. This project will install a new Bank 2 and new 1104 breaker and feeder outlet at Mormon Sub and transfer load from East Stockton Sub to Mormon Sub. After this work, Mormon Sub will have two 30 MVA banks.

7.3.2 Estimate Capital Cost for Candidate Deferral Projects – Step 14

Estimated project costs evolve as a project develops and the scope of work becomes more defined. PG&E considers the definition of the CDOs as conceptual with a relatively general definition of scope. They consider the unit cost uncertainty level for all these projects as Class 5 as defined by the American Association of Cost Engineers (AACE).

PG&E considers the CDOs as being at the earlier stages of development and the associated costs are estimated using either estimates of specific equipment and unit costs for work required, or historical costs from completed projects. The costs used for the development of these CDOs are the same costs as used in the GRC.

Cost breakdown for five Tier 1 and 2 CDOs are shown below in Table 7-15. The costs provided in this table are consistent the costs shown in DDOR Appendix A, Planned Investments. These costs cannot be reproduced independently because they use PG&E data based on their historic costs and equipment bids.

Table 7-15: Cost Data for Selected Candidate Deferral Opportunities

COST DATA FOR CD PROJECTS				
DDOR ID	PROJECT NAME	ROUGH PROJECT DEVELOPMENT COST	SCOPE	NOTES
DDOR026	Mormon Bank 2 (2025)	$16,680,000	$4.4M to install two new 60 kV breakers, $8.4M to install one new transformer, $1.4M for one new circuit breaker, $1M for new control building, $1.48M to install 9,250 feet of new circuit @ $160/ft	Not included in 2023 GRC
DDOR178	Belle Haven Bank 4 (2024)	$14,700,000	$6.5M to replace existing transformer, $5.3M to replace 12 kV OH Bus Sect E with Metal-Clad switchgear with four feeder bays, $2.2M to install 5450 feet of new UG cable @ $410/ft. $0.6M to Install five 3W/3W UG switches @$130,000 each, $0.1M to install two OH SCADA switches @ $45,000 each	Uses 2023 GRC costs
DDOR070	Embarcadero 1118 (2025)	$2,501,000	$1M to re-cable 910 feet inside substation@ $1,100 per foot, $1.5M to recable 2500 feet outside substation at $600/ft.	Uses 2023 GRC costs
DDOR105	Anita 1105 (2024)	$2,500,000	$1.4M to install new circuit breaker, $0.88M to reconductor 5500 ft OH line @ $160/ft, $0.22M to swap outlets at substation	Not included in 2023 GRC, but uses 2023 GRC costs
DDOR088	Ripon 1705 (2024)	$1,900,000	$1.4M to install new circuit breaker, $0.5M for 3,125 feet of new overhead @$160/ft	Uses 2023 GRC costs

7.4 Processes to Develop Candidate Deferral List and Prioritize

7.4.1 Development of Candidate Deferral Projects – Step 15

As mentioned earlier, the technical screening is a continuous process. As capacity and/or reliability projects are identified and created, they are entered into LoadSEER which creates a list of grid needs. This LoadSEER list is used as input for capacity projects in the GNA. The need date for capacity projects is identified in LoadSEER and entered in the GNA. Because of project lead times, an in-service date may be later than the need date. In these cases, PG&E must develop a “work around” alternative until the project can be completed.

Line segment overload and low voltage conditions are identified from the CYME, PG&E’s load flow and voltage analyst tool. Each line segment with an overload or low voltage condition based on the load forecast is entered into the GNA. Normally these conditions are near term and are filtered out by the timing screen. As mentioned earlier, PG&E received a Motion for Extension approval on August 10, 2021, to delay publishing of grid needs resulting from line section analyses, which are primarily voltage support and distribution capacity needs. PG&E provided a supplemental filing on October 15, 2021, per the approved Motion for Extension.

The DDOR in-service dates are used for as the timing screen.

7.4.2 Development of Operational Requirements – Step 16

Operational requirements are developed in LoadSEER that provides loading by month and hour for the peak weekday and weekend day of the month. An hourly profile is developed for the peak weekday and weekend day for the month, identifying the times and duration of any overload.

Since a weekday could be any weekday in the month, it is assumed for the purposes of determining the maximum calls (or days) per month, the DER could be called upon every weekday that month. The same approach is taken for weekend days. Therefore, a need for a DER on one weekday would result in a requirement of approximately 20+ calls per month (depending upon the number of weekdays in the month) and a maximum of approximately 8 calls per month (depending upon the number of weekend days per month) if the overload only occurs during a weekend day.

The LoadSEER results are put into a separate Excel workbook that identifies the service requirements which include the peak year, month ranges, max/min and times and the weekday/weekend needs such as start/end times, load ranges, and potential calls/year. PG&E adds an hour to each side of the overload time to reflect when an overload extends to part of an hour before or after the hour identified by LoadSEER.

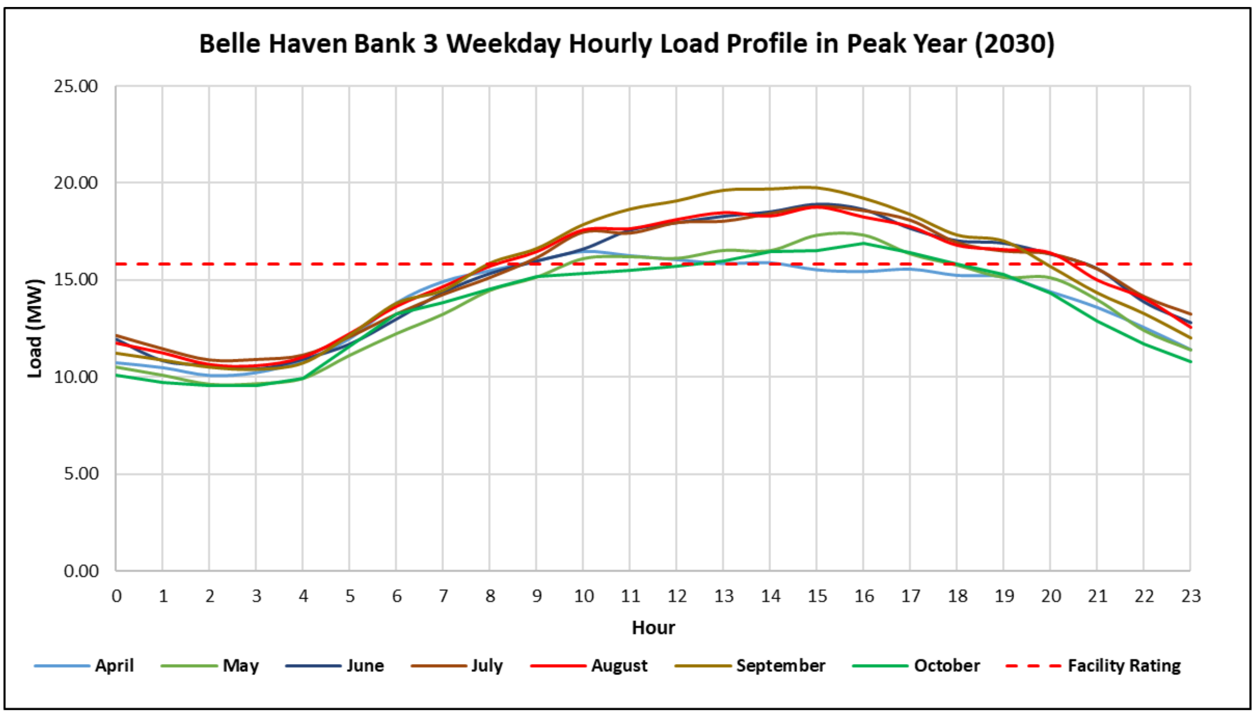
PG&E demonstrated the development of operational requirements for Belle Haven Bank 3.

It is observed PG&E has a relatively conservative approach to some of the operational requirements. If there is a peak weekday during the month, it is assumed for the purposes of determining the maximum calls (or days) per month, the DER could be called upon every weekday that month. This is reasonable for identifying potential availability, but we believe it is overly conservative to use it to develop the total number of calls and/or hours for use in the LNBA metrics (LNBA/MWh-yr.). It is unlikely they will be needed for every day of the month. This approach could have an impact on the LNBA metrics resulting in negative rankings for some CDOs. <u>It is recommended PG&E consider an approach that captures the likely distribution over 8760 hours for identifying the number of hours required</u>.

7.4.2.1 Belle Haven Bank 3 Operational Requirements

The driver for this new bank is the forecasted overload of the Belle Haven Bank 3. Therefore, the operational requirements are determined by the existing bank maximum 10-year load profile. In Figure 7-16, below, shows the weekday hourly forecast for the peak year, 2030.

Figure 7-16: Bell Haven Bank 3 Hourly Load Profile for 2030



The Operational Requirements are produced in LoadSEER and shown in Table 7-16.

Table 7-16: Belle Haven Bank 3 Operational Requirements

WEEKDAY+WEEKEND Combined Requirements													
Distribution Service Requirements	Max Grid Need (MW)	January	February	March	April	May	June	July	August	September	October	November	December
DER Grid Need (MW)	3.94	0.00	0.00	0.00	0.76	1.53	3.11	2.99	2.93	3.94	1.11	0.00	0.00
Peak Year	2030												
Starting Need Month	4												
Last Need Month	10												
Calls/Year	163	0	0	0	22	23	20	23	22	30	23	0	0
Max Need Duration	12	0	0	0	7	8	12	12	12	12	6	0	0
Start Time	8:00 AM				9:00 AM	10:00 AM	9:00 AM	9:00 AM	9:00 AM	8:00 AM	1:00 PM		
End Time	9:00 PM				4:00 PM	6:00 PM	9:00 PM	9:00 PM	9:00 PM	8:00 PM	7:00 PM		
Number of Events	1												
Max Energy (MWH)	47	0.00	0.00	0.00	5.33	12.22	37.35	35.86	35.19	47.27	6.68	0.00	0.00

WEEKDAY NEEDS													
Distribution Service Requirements	Max Grid Need (MW)	January	February	March	April	May	June	July	August	September	October	November	December
DER Grid Need (MW)	3.94	0.00	0.00	0.00	0.76	1.53	3.11	2.99	2.93	3.94	1.11	0.00	0.00
Starting Need Month	4												
Last Need Month	10												
Calls/Year	154	0	0	0	22	23	20	23	22	21	23	0	0
Max Need Duration	12	0	0	0	7	8	12	12	12	12	6	0	0
Start Time	8:00 AM				9:00 AM	10:00 AM	9:00 AM	9:00 AM	9:00 AM	8:00 AM	1:00 PM		
End Time	9:00 PM				4:00 PM	6:00 PM	9:00 PM	9:00 PM	9:00 PM	8:00 PM	7:00 PM		
Number of Events	1	0	0	0	1	1	1	1	1	1	1	0	0

WEEKEND NEEDS													
Distribution Service Requirements	Max Grid Need (MW)	January	February	March	April	May	June	July	August	September	October	November	December
DER Grid Need (MW)	0.25	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.25	0.00	0.00	0.00
Starting Need Month	9												
Last Need Month	9												
Calls/Year	9	0	0	0	0	0	0	0	0	9	0	0	0
Max Need Duration	1	0	0	0	0	0	0	0	0	1	0	0	0
Start Time	4:00 PM									4:00 PM			
End Time	5:00 PM									5:00 PM			
Number of Events	1	0	0	0	0	0	0	0	0	1	0	0	0

2030		1/1/2030	2/1/2030	3/1/2030	4/1/2030	5/1/2030	6/1/2030	7/1/2030	8/1/2030	9/1/2030	10/1/2030	11/1/2030	12/1/2030	1/1/2031
Number of Days in Peak Year	365	31	28	31	30	31	30	31	31	30	31	30	31	
Number of Weekdays*	261	23	20	21	22	23	20	23	22	21	23	21	22	
Number of Weekends	104	8	8	10	8	8	10	8	9	9	8	9	9	
* Holidays are not excluded														

7.4.3 Prioritization of Candidate Deferral Projects into Tiers – Step 17

As part of this step, the prioritization metrics spreadsheet in the PG&E DDOR Report Appendix C: Prioritization Metrics Workbook was used to review the raw data, normalization process, assignment of red flags and final scoring and ranking of the CDOs. The methodology used followed the description provided by PG&E. The prioritization or assignment of Ties for the CDOs are consistent with the calculations in this appendix.

7.4.4 Calculate LNBA Values – Step 18

Development and Use of LNBA Values

The Locational Net Benefits Analysis (LNBA) value is the unitized net present value (NPV) of the savings associated with deferring a planned project. The deferral value is the revenue requirement associated with the planned project which includes annualized capital and operations and maintenance (O&M) costs. The LNBA value is typically expressed as a $/MW-year value, determined by dividing the deferral value by the product of two values – the number of years of deferral and the maximum amount (MW) of need during the deferral period. The LNBA value is used as an indicator 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. In the DDOR report, actual LNBA values (i.e., not ranges) are reported for both Planned Investments and Candidate Deferral projects. The LNBA values are also used in the calculation of prioritization metrics.

Approach

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

Deferral Timeframe

Deferral period is a key input to the LNBA calculation. In the 2021 DDOR, PG&E uses a 10-year deferral timeframe as required by the 2020 May ALJ Ruling Reform #5. For example. If the operating date of a project is in 2024, then the deferral period is 7 years (i.e., defer from 2024 to 2030). PG&E calculated the LNBA values for planned investments (provided in units of $/MW-yr, $/Vpu-yr, or $/MVAR-yr).

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 10-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 ten 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. In the E3-based LNBA calculation tool, the deferral value for a multi-year deferral is calculated using a single NPV formula and not as the sum of the NPV of 1-year deferral values as stated above.

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:

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 cost is also subject to inflation adjustments.

The complete expression of the avoided cost 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 E3-based LNBA calculation tool used by PG&E calculates the multi-year deferral using a single NPV formula with the year of deferral as an input, instead of summing the NPV of 1-year deferrals.

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.
- O&M Costs: Cost of O&M as per utility's practice. Expressed as a percentage of the project's capital cost.

In general, PG&E's LNBA calculations followed the same calculations as those included 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.

Key inputs

The key inputs to the LNBA calculation are shown in the table below. Only the inputs corresponding to substations, primary feeders, and IT are shown in the Table below for simplicity because those were the only ones used. PG&E used a discount rate of 10%. PG&E indicated that the 10% discount rate is equal to PG&E's incremental cost of capital. PG&E's incremental cost of capital is intended to be a forward-looking long-term cost of capital, whereas PG&E's authorized cost of capital is a short-term cost of capital that largely reflects the cost of existing financing, not new or incremental financing. One other key input for the LNBA calculation is the capital cost of equipment for each project.

Table 7-17: Key Inputs for LNBA Calculation

Input	General	Substation Bank	Primary Feeder	Poles and towers	Source
Revenue Requirement Multiplier (Fixed Costs)	144.87%	143.64%	146.11%	150.01%	PG&E assumptio n
Revenue Requirement Multiplier With O&M	247.12%	185.84%	308.40%	309.82%	PG&E assumptio n
Equipment Inflation	2.50%	2.50%	2.50%	2.50%	Standard assumptio n in LNBA Calculator
O&M Inflation	2.50%	2.50%	2.50%	2.50%	Standard assumptio

					n in LNBA Calculator
O&M Factor	5.15%	2.13%	8.18%	8.18%	PG&E assumptio n
O&M Old Eqpt	0%	0%	0%	0%	PG&E assumptio n
Book Life	46	46	46	44	PG&E assumptio n
RECC	0.04721777 8	0.04721777 8	0.04721777 8	0.0479543 5	Calculated
Discount rate net or project inflation (5/yr.)	4.17%	4.17%	4.17%	4.17%	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: DDOR082, GNA Facility Name: Coalinga No 1 Bank 2) as shown in Table 7-18. 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 7-18: Coalinga No 1 Bank 2 Work LNBA Verification

Note: This table has confidential information highlighted in gray which was redacted in this public report

#	LNBA Item	Values shown in DDOR Report	IPE Calculations based on E3 LNBA formula	E3 LNBA formula
1	Project ID / Name	DDOR082	DDOR082	Input Verified
2	GNA Facility Name	Coalinga No 1 Bank 2	Coalinga No 1 Bank 2	Input Verified
3	Planned Investment Type	Bank	Bank	Input Verified
4	Project Cost ($k)	6500.00	6500.00	Input Verified
5	Revenue Requirement Multiplier	1.44	1.44	Input Verified
6	Discount Rate (%/yr.)	0.07	0.07	Input Verified
7	Equipment Inflation	0.025	0.025	Input Verified
8	O&M Inflation	0.025	0.025	Input Verified
9	O&M Factor	0.00	0.00	Input Verified
10	Book Life	46	46	Input Verified
11	DER Install Year	5/1/2024	5/1/2024	Input Verified
12	Cost year basis	8/1/2021	8/1/2021	Input Verified

13	Analysis Year	2021	2021	Input Verified
14	Deferral Years	7.00	7.00	Input Verified
15	Number of no deficiency years after the DER Install yr.	0.00	0.00	Input Verified
16	Incremental O&M Cost	0.00	0.00	C4*C9
17	RECC	0.05	0.05	(C6-C7)/(1+C6)*(1+C6)^C10/((1+C6)^C10-(1+C7)^C10)
18	Discount rate net or project inflation (5/yr.)	0.04	0.04	(1+C6)/(1+C7)-1
19	RR Install Yr $'s	9992.66051680428 *	9992.66	C4*C5*(1+C7)^((C11-C12)/365.25)
20	RR * RECC	471.83	471.83	C19*C17
21	Capital Benefit in Install Year	2931.91	2931.91	PV(C18,C14,-C20,0,1)
22	O&M Deferral Benefit in Install Year	0.00	0.00	PV(C18,C14,-C16,0,1)*(1+C8)^(C11-C12)/(1+C18)^B15
23	Value of Deferral Benefits ($000s) in Install Year			C21+C22
24	Value of Deferral Benefit ($000s) in 2021			C23/(1+C6)^((C11-C12)/365.25)
25	Max Need (MW/Vpu/MVAR)*			Verified
26	Normalized Deferral Benefit ($000s/MW-yr.)			C24/C25/C14

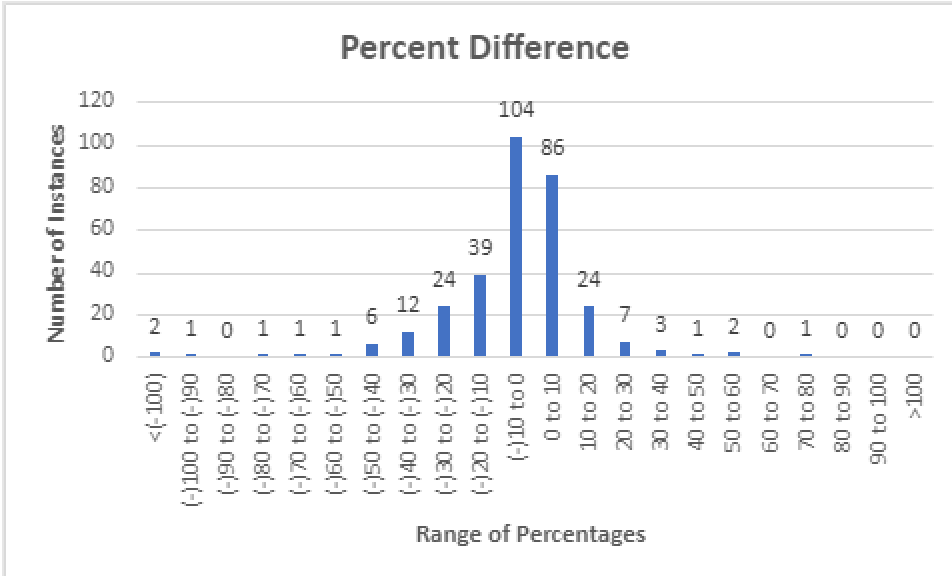
*The value calculated for revenue requirement by PG&E is slightly different since it takes partial year into account in the present value calculation whereas the E3 LNBA does not.

7.4.5 Compare 2019 Forecast and Actuals at Circuit Level for 2019 – Step 19

A review of the 2019 forecast against the actual 2020 loads was conducted. In this step the forecasted 2020 loads for 315 randomly selected feeders were compared with the feeder's 2020 actual scrubbed peak loads (adjusted for temperature or load transfers if necessary). PG&E provided the 2020 actual scrubbed loads and the 2020 load forecasts were obtained by the IPE from the 2019 GNA appendix.

The analysis process included calculation of the delta between the actual and forecasted load, percent difference and overloads. Figure 7-17: Percent Difference Distribution, below shows the percent difference distribution of the 315 needs.

Figure 7-17: Percent Difference Distribution



It can be inferred that the about 60% of the forecasted loads are within +/-10% of the actual values and about 80% of the forecasted loads are within +/-20% of the actual values.

In addition, a brief review of the impact on the distribution facilities due to actual loads exceeding the forecast. Table, Facilities with Overloads, shown below provides the overload information. It was observed that eight facilities out 315 or 2.5% were overloaded. Three of these facilities, Santa Rosa A 1102, Corral 1102, and Emerald Lake 0402 were overloaded above 10%. It was also observed, four facilities, Loyola 1102, Highway 1102, Santa Rosa A 1102, and Country Club 0402 had forecasts that were the same or greater than the facility ratings. A review of planned investments identified work to mitigate these overloads. Based on this brief review, the overload rate appears acceptable especially since four of the overloads were five percent or less.

Table 7-19: Facilities with Overloads

Facility Name	Forecast (MW)	Actual 2020 Load	Facility Rating	Overload (%)
LOYOLA 1102	13.58	12.8079	12.19	5%
HIGHWAY 1102	13.28	12.6725	12.23	4%
SANTA ROSA A 1102	11.72	11.1721	8.87	26%
ALMADEN 1102	11.57	12.2733	11.82	4%
COUNTRY CLUB 0402	2.71	2.9531	2.7	9%
CORRAL 1102	10.19	11.8093	10.46	13%
EMERALD LAKE 0402	1.73	2.839	2.34	21%
SAN CARLOS 0402	1.97	2.4752	2.35	5%

7.5 Other IPE Work

7.5.1 Review Implementing of Planning Standard and/or Planning Process – Step 20

This review is planned for completion after the IPE DPAG Report is published.

7.5.2 Review List of Internally Approved Capital Projects – Step 21

This review is targeted for completion in November according to the IPE Plan. The results of this review will be included in the Post DPAG Report.

7.5.3 Respond to and Incorporate DPAG Comments – Step 22

The IPE was available during the PG&E DPAG meeting and the PG&E Follow-Up DPAG meeting to respond to questions raised and has also responded to written questions posed to the IPE by stakeholders which is included in Appendix B.

7.5.4 Track Solicitation Results to Inform Next Cycle – Step 22

This review is planned for completion by Q1 of 2022.

7.5.5 Treating confidential material in the IPE report – Step 24

The IPE work products have followed the process and steps included in this Business Step in developing its IPE Final Report.

Appendix A IPE Scope

R.14-08-013, A.15-07-005, *et al.* ALJ/RIM/nd3

Attachment A
Listing of Schedule and IPE-Specific Reforms for the 2020-2021 DIDF Cycle

1. IPE-specific reforms for the 2020-2021 DIDF Cycle are implemented within the IPE Scope of Work presented in Attachment B.
2. IOU contracts with the IPE for the full scope of work identified in Attachment B shall be executed by the IOUs to allow for IPE Plan development to begin as soon as possible, ideally on or before **April 17, 2020**.
3. The IOUs shall work with the IPE and Energy Division to develop IPE Plans specific to each IOU such that the IPE can submit the Draft IPE Plans to Energy Division for review on or before **May 15, 2020**.
4. The IPE scope of work may be modified by Energy Division as needed for the IPE to successfully complete each assignment. The IOUs will promptly submit a Tier 1 Advice Letter to notice changes in scope should a scope change differ significantly from the scope described in Attachment B. Minor changes should not necessitate an Advice Letter filing.
5. As required by Energy Division on an annual basis, Pre-DPAG and Post-DPAG activities may include workshops; new, re-opened, suspended, or modified working groups (e.g., Distribution Forecast Working Group); and IOU presentations and deliverables.
6. During the Post-DPAG period and in consultation with the IPE, Energy Division may identify exemplary GNA/DDOR documentation components, analytical approaches, or data strategies implemented by one or more IOUs and require that each IOU implement the reform in future DIDF cycles.

(end of Attachment A)

- 1 -

Attachment B
IPE Scope of Work for DIDF Implementation

Term

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

Pre-DPAG Period

- Develop an ***IPE Plan*** for each IOU describing the GNA/DDOR review process and detailed approach to Verification and Validation of all data used by the IOUs to prepare their DIDF filing materials.
    - Verification and Validation will include a thorough investigation of the following IOU processes, among others:
        - Collecting circuit loadings and performing weather adjustments;
        - Determining load and DER annual growth on the system level;
        - Disaggregating load and DER annual growth to the circuit level;
        - Checking sum of all disaggregated load and DERs against system-level values;
        - Adding incremental known loads to circuit level forecasts;
        - Developing load, DER, and net load profiles and determining net peak loads;
        - Adjusting for extreme weather;
        - Comparisons to equipment ratings to determine if ratings will be exceeded;
        - Incorporating load transfers, phase transfers, correcting data errors;
        - Compiling GNA tables showing need amount and timing; and
        - Following the IOU's planning standard and/or planning process.
    - GNA/DDOR report review will include an in-depth analysis of the following IOU steps, among others:
        - Developing recommended solutions (planned investments);
        - Implementing the IOU's planning standards and/or planning process;
        - Estimating capital costs for planned investments;

  - Developing list of candidate deferral projects through application of screens (timing and technical);
  - Developing operational requirements;
  - Prioritization of candidate deferral projects into tiers;
  - Calculating LNBA values; and
  - Comparing prior-year forecast and actuals at circuit level for candidate deferral projects.
- Work directly with the IOUs and Energy Division to develop draft plans as needed. Development of the draft IPE Plans may include, among other activities:
  - Meeting with the IOUs and Energy Division to identify and understand each business process and tool used to complete their GNA/DDOR filings.
- Facilitate or participate in stakeholder workshops to receive feedback on the IPE Plans.
- Review and incorporate comments in the final IPE Plans.
- Submit final IPE Plans to Energy Division and the IOUs with recommendations for future improvements to the plans.
- Other technical support assignments as defined by Energy Division to ensure the IPE and Energy Division will receive from the IOUs the data and cooperation necessary to complete the required evaluation of the GNA/DDOR filings.

DPAG Period

- Participate in all workshops and meetings during the DPAG period. Prepare and deliver presentations or handouts as requested by Energy Division (*e.g.*, final IPE Plan presentations).
- Develop an ***IPE Preliminary Analysis of GNA/DDOR Data Adequacy*** for all three IOUs.
- Review any comments on the preliminary analysis that may be received and discuss the results with Energy Division.

- Facilitate meetings with Energy Division and the IOUs to correct data inadequacies and prepare further documentation and provide technical support as needed.
- Fully implement each IPE Plan as defined in the final IPE Plans.
- Develop an ***IPE DPAG Report*** for each IOU presenting GNA/DDOR review findings and Verification & Validation outcomes.
- Submit the draft reports to Energy Division for review and (if necessary) to the IOUs to check for confidential information that may be included or to clarify specific details.
- Circulate the final IPE DPAG Reports to stakeholders (public and confidential versions).
- Other technical support assignments as defined by Energy Division to ensure the DPAG process is successfully completed.

Sample Size

- The scope of review conducted by the IPE for each IOU process may encompass the full set of circuits/projects or a subset/sample of circuits or projects. Where sampling is determined to be appropriate by the IPE in consultation with Energy Division, the size of the sample set for each case will be determined by the IPE based on the application of engineering judgement.

Post-DPAG Period

- Develop a single ***IPE Post-DPAG Report*** covering all three IOUs; comparing their current and prior filings; evaluating DIDF DER procurement, operational, cost, and contingency planning outcomes; reviewing IOU compliance; and making recommendations for process improvements and DIDF reform.
- Coordinate with and support the Independent Evaluator (IE) with IE activities and the development of IE reports as needed.
- Submit the draft report to Energy Division for review and (if necessary) to the IOUs to check for confidential information that may be included.

Appendix B 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 be directed to PG&E and/or the IPE per the CPUC Ruling. There were a number of responses and comments included in a separate file from the file containing this report.

B.1 Comments and Questions Directed to IPE

Public Advocates Office Comments

Responses to comments and questions directed to the IPE are included in the pages below.

B.2 PG&E DPAG Survey Responses

PG&E's responses to comments and questions included in their survey and those provided to them following the DPAG Webinar are included in a separate file.

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The Public Advocates Office's Questions and Comments for the Independent Professional Engineer

R.14-08-013 et al. (Distribution Resources Plan)
September 24, 2021

NOTE: THE IPE's RESPONSE IS INCLUDED IN THIS DOCUMENT HIGHLIGHTED IN YELLOW

Submitted by	**Organization**	**Date Submitted**
Richard Khoe Public Utilities Regulatory Analyst Phong Ly Utilities Engineer David Matthews Utilities Engineer Phone: (415) 703-3451 Email: phong.ly@cpuc.ca.gov	Public Advocates Office – California Public Utilities Commission 505 Van Ness Avenue San Francisco, CA 94102	September 24, 2021

I. INTRODUCTION

In accordance with the June 21, 2021 *Administrative Law Judge's Ruling on Recommended Reforms for the Distribution Investment Deferral Framework Process*, the Public Advocates Office at the California Public Utilities Commission (Cal Advocates) submits the following comments in response to the Independent Professional Engineer's (IPE) Preliminary Analysis presented at the Distribution Planning Advisory Group (DPAG) Meetings held between September 15, 2021 through September 20, 2021 for San Diego Gas & Electric Company (SDG&E), Southern California Edison Company (SCE), and Pacific Gas and Electric Company (PG&E).

II. COMMENTS REGARDING IPE'S PRELIMINARY ANALYSIS

Cal Advocates provides the following questions regarding the IPE's 2021 Preliminary

Analysis.

1. Despite the utilities' efforts to standardize the prioritization metrics used for ranking candidate deferral opportunities, there are still fundamental differences in logic applied by each investor-owned utility (IOU). With regards to the Forecast Certainty metric, there is a conflicting difference between how the utilities assign this score. While SCE and SDG&E assign higher Forecast Certainty score for planned investments when there are likely increases in load such as customer requests for new loads, PG&E assigns a lower Forecast Certainty score when there is a high likelihood of requests for new customer loads. The IPE should investigate the consistency of how the Forecast Certainty metric is scored among the IOUs and whether a consistent application of the Forecast Certainty metric would result in different candidate deferral prioritization for each IOU.

   IPE Response: We noticed the same difference in approach among the IOUs. We plan to address that in our IPE DPAG Report.

2. The IPE should validate and verify projects that were relegated to Tier 3 projects due to flagging but ranked relatively highly on prioritization metrics. While these projects would have been ranked in a higher tier, the flag automatically relegates the projects to Tier 3 and designates the projects as opportunities with low probability of success for sourcing. Among PG&E and SCE, there are numerous projects meeting this criterion that should be investigated. For example, PG&E's Appendix C of its 2021 DDOR Report shows that the McKee 1102 planned investment ranked 7th overall out of the 45 planned investments. Without the flag on the Market Assessment metric, it appears that McKee 1102 would have been listed as a Tier 1 Candidate and thus, would have been identified for solicitation. SCE's Joint Prioritization Metric Workbook shows that the Alberhill System Project (ASP) was ranked 1st out of the 15 planned investments, ranking 1st in the Cost Effectiveness metric and 2nd in the Market Assessment metric. Without the flag on the Market Assessment metric, it appears that the ASP would have been listed as a Tier 1 Candidate and thus, would have been identified for solicitation.

   IPE Response: We did perform such a review before the DPAG presentations. A quick summary is listed below however we will include more detail in our Post DPAG

Reports. As background, the IOUs did indicate when they presented the joint prioritization metrics to the ED (and IPE) in the spring of 2021 that the Flags mechanism would be the same for all three IOUs but the logic that drove the Flags would be different and based upon their individual experience.
- For SDG&E there were not Flags assigned.
- For SCE only one flag was assigned as noted in the question – a Flag for ASP. While it would appear that without such a flag ASP would be Tier 1 and thus considered for procurement we believe that for other reasons ASP would not have moved to procurement.
- For PG&E there were several Flags assigned. They applied Flags for Cost effectiveness based upon the cost of the planned investment (<$1M), for Forecast Certainty (Date>2026) and Market Assessment (>3 needs or RT). In our first review summarized in the report presented at the DPAG we did initially ignore some of the Flags and focused on projects with high cost-effectiveness rankings to see which might be close to the projects that were already ranked high on CE and thus should be considered for Tier 1. We reviewed again all projects ignoring the Red Flags prior to the PG&E Follow up DPAG meeting and raised a project that we recommended be considered by the DPAG for Tier 1. We did look at McKee 1102 project and ignoring the Flag the cost-effectiveness ranking of this project is quite low and, in our opinion, not a strong candidate for Tier 1, and not as strong as other projects with flags.
As indicated above, we will also summarize these reviews in our IPE DPAG Report.

When it comes to pre and post-application projects they tend to be in a category all their own. We are considering recommending the prioritization process would be more insightful if there were two versions – one with them and one without them.

3. As stated in the IPE report for SCE's 2019 GNA/DDOR report, the IPE should continue its work in determining whether the needs of the Alberhill System Project can be separated to facilitate consideration in the Distribution Investment Deferral Framework (DIDF) and whether the overall cost of the segregated project provides a lesser overall cost to the ratepayer compared to the combined project. In the 2019 SCE DPAG follow-

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up webinar, SCE ranked the Alberhill System Project as a top-ranked project for deferral. The IPE notes that "based solely on the three quantitative prioritization metrics, the Alberhill System Project would be a logical choice for Tier 1 consideration since it has the highest Overall Score, the highest Cost Effectiveness score and good scores in the other two metrics."[1] In the 2020 GNA/ DDOR Report, SCE ranked the ASP as a top candidate for deferral; however, SCE states that separating the costs and components of the ASP is not feasible due to the project being designed as an integrated solution.[2] In SCE's 2021 GNA/ DDOR report, SCE ranks the ASP as the top-ranked candidate for deferral but relegates the ASP to Tier 3 because of a flag on the Market Assessment metric. The consistent high ranking of the ASP over the past three DIDF cycles merit further consideration for the ASP within the DIDF process.

<u>IPE Response</u>: Alberhill is a very complex project that does not fill well with the DIDF process or ranking metrics as we saw on the Follow up DPAG call. We will do our best to shed some light on it in the IPE DPAG Report as indicated on the SCE call or at the latest in the Post DPAG Report in March of 2022..

4. Use of the red, amber, green (RAG) approach for ranking projects means that projects are selected based on how the projects rank relative to one another rather than necessarily the underlying characteristics of the respective projects. For example, in DIDF cycles where there are many good candidate projects, this means some of these projects may not be selected for deferral. The IPE should include discussion and recommendations in its Post DPAG Report on Revised Reform #32, discussing the Green Power Institute's (GPI) and the IOUs' comments about prioritization changing from a relative ranking among the candidate deferral projects identified each year to a ranking based on baseline/absolute threshold values that would carry over each year.

   IPE Response: We plan to include some discussion of this in the IPE Post DPAG Report.

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[1] Independent Professional Engineer SCE 2019 GNA/ DDOR Report, p. 24.
[2] SCE 2020 Grid Needs Assessment and 2020 Distribution Deferral Opportunities Report, p. 66.

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5. In terms of selecting the projects for the Partnership Pilot, there are strong differences between the approaches of each IOU. For example, SCE takes customer characteristics, particularly location, into account. In contrast, SDG&E and PG&E's selection criteria do not take customer characteristics into account. The IPE should investigate the how the IOUs select Partnership Pilot projects and determine if a consistent approach is merited, and if so, determine which approach is preferable.

   IPE Response: We plan to include some discussion of this in the IPE DPAG Report.

6. For SDG&E, most of the planned investments identified in current and past DIDF cycles have not passed the timing screen. In the 2018-2019 cycle, out of the 23 planned investments, one planned investment passed the timing screen. In the 2019-2020 cycle, out of the 10 planned investments, none passed the timing screen. In the 2020-2021 cycle, out of the 19 planned investments, none passed the timing screen. In the 2021- 2022 cycle, out of the 12 planned investments, two planned investments passed the timing screen. During the 2021 SDG&E DPAG presentation, when asked why there were several planned investments with an in-service year of 2022 and why those plannedinvestments were not included in past DIDF cycles, SDG&E attributed this to recent customer applications for load growth projects that were not known during previous DIDF cycles. As discussed in the 2021 IPE Post DPAG report, the IPE should continue its verification and validation work to confirm the timing need in this DIDF cycle, perform a detailed analysis of the circuit and bank level capacity for needs forecasted in the first three years of the DIDF, and determine the contributing factors that caused grid needs to change from the 2020 to 2021 GNA/ DDOR reports. It is unclear why the timing screen is a significant factor for SDG&E and less of a factor for the other IOUs.

   IPE Response: We plan to include some discussion of this in the IPE or Post DPAG Report.

Appendix C Copy of the IPE Plan

Note: The 2021/2022 IPE Plan for PG&E is included in a separate file from the file containing this report.

Appendix D Documents Received

The IPE received many sets of data from PG&E during the review. Listed below are the documents provided to the IPE during the course of the review. These actual documents are provided as separate documents from the body of this report due to their size.

Two lists of documents provided to the IPE by PG&E are provided below. One lists the set of documents that are considered Public since they do not contain any confidential information. The second list contains all of the documents that are declared confidential and are not available to the public. This second list also includes documents that are not confidential such that the two lists include all of the documents that are available to the Public or the CPUC.

D.1 List of Documents Provided – Public Set

- Public PGE 2021 DDOR
- Public PGE 2021 GNA
- TD-1004P-05 Generic and Custom Distribution Transformer Ratings
- Forecast Shape Export - ANITA 1101 - 2021-07-08 0858
- Forecast Shape Export - BELLE HAVEN BANK 3 - Belle Haven Bank 4
- Forecast Shape Export - BONITA 1102 - Bonita Bank 2
- Forecast Shape Export - BONITA BANK 1 - Bonita Bank 2
- Forecast Shape Export - CONCORD NO 1 0401 - 2021-09-14 0742
- Forecast Shape Export - CONCORD NO 1 0402 - 2021-09-14 0742
- Forecast Shape Export - DEEPWATER 1108 - uses EV Charging Local Delivery Fleet Shape
- Forecast Shape Export - EDENVALE 2109 - 2021-07-08 0841
- Forecast Shape Export - FIGARDEN 2102 - 2021-07-08 0857
- Forecast Shape Export - FIGARDEN 2102 - 2021-09-14 0818
- Forecast Shape Export - GREEN VALLEY BANK 3 - Green Valley Bank 3
- Forecast Shape Export - LAKEWOOD 1104 - 2021-07-08 0851
- Forecast Shape Export - LLAGAS 2101 - 2021-07-08 1533
- Forecast Shape Export - MANTECA BANK 7 - Ripon 1705
- Forecast Shape Export - MERIDIAN 1102 - 2021-07-08 0856
- Forecast Shape Export - RINCON 1101 - 2021-07-08 0855
- Forecast Shape Export - RIPON 1704 - Ripon 1705
- Forecast Shape Export - RIPON BANK 2 - Ripon 1705
- Forecast Shape Export - SAN LUIS OBISPO 1108 - uses EV charging Transit Agency shape
- Forecast Shape Export - SARATOGA 1107 - 2021-07-08 0853
- Forecast Shape Export - STOREY 1106 - Bonita Bank 2
- Forecast Shape Export - VINEYARD 2104 - uses EV DC Fast Charging Station shape
- Forecast Shape Export - WYANDOTTE 1107 - 2021-07-08 0803
- Forecast Shape Export - YOSEMITE 0402 - 2021-07-08 0854
- IPE 2021 Request SpatialForecast
- IPE request 2021 Adjustments
- Water Data 2020 for upload
- 9i Forecast 1MW Shape Export
- 10 Proposed Feeders 2021 - Rev1
- AAEE All 2020_2030
- AAEE_Bus_Load_Projection_PG&E_2019-20 (Public)
- Adjusted PGE Load Modifiers Mid Baseline Mid AAEE CEDU2019
- CED 2019 PGE LDEV Energy Stock
- Default Commercial Shape
- ESN 2020-2030 Charge
- ESR 2020-2030 Charge
- EV Res Load 2020-2030
- Feeder Loads from 2020
- follow up list 9.01.21 v10_PG&E
- IPE follow up list 9.15.21 v12_PG&E
- IPE Request PV Commercial 2021_2030
- IPE Request PV Residential 2021_2030
- PV and Storage Data by Forecast Zone and Sector 2019 CEDU
- Questions on Costs for Selected Candidate Deferral Projects
- System LoadShape Energy_Storage_Charge
- System LoadShape Energy_Storage_Discharge
- Belle Haven Bank 3 - DER Serv Req
- Belle Haven Bank 3 - Load Profile
- LoadSEERScreenshotAnitaBank1
- LoadSEERScreenshotConcord401402
- LoadSEERScreenshotNordBank1
- LoadSEERScreenshotNordBank2
- Mormon 1102 - DER Serv Req
- Mormon 1102 - Load Profile
- Energy Storage Charge
- Energy Storage Discharge

D.2 List of Documents Provided – Confidential Set

- PGE_2021_DDOR_Appendix_I_Confidential_102221
- PGE_2021_DDOR_Full_Conf_081621
- PGE_2021_GNA_Full_Conf_081621
- CONF_AAEE_Bus_Load_Projection_PG&E_2019-20
- PGE_2021_DDOR_Appendix_A_B_confidential
- PGE_2021_DDOR_Appendix_C_JointIOUPrioritizationMetrics_Confidential
- PGE_2021_DDOR_Appendix_D_CD LNBA_Confidential
- PGE_2021_DDOR_Appendix_E_PI LNBA_Confidential
- PGE_2021_DDOR_Appendix_G_Forecast Questionnaire Results_Confidential
- PGE_2021_DDOR_Appendix_H_Confidential_102221
- PGE_2021_DDOR_Appendix_I_PI-Line sections-LNBA_Confidential_102221
- PGE_2021_GNA_confidential_Appendix_D-G

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

AT&T
Albion Power Company

Alta Power Group, LLC
Anderson & Poole

Atlas ReFuel
BART

Barkovich & Yap, Inc.
California Cotton Ginners & Growers Assn
California Energy Commission

California Hub for Energy Efficiency Financing

California Alternative Energy and Advanced Transportation Financing Authority
California Public Utilities Commission
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
Crossborder Energy
Crown Road Energy, LLC
Davis Wright Tremaine LLP
Day Carter Murphy

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

East Bay Community Energy Ellison Schneider & Harris LLP Energy Management Service
Engineers and Scientists of California

GenOn Energy, Inc.
Goodin, MacBride, Squeri, Schlotz & Ritchie
Green Power Institute
Hanna & Morton
ICF
International Power Technology

Intertie

Intestate Gas Services, Inc.
Kelly Group
Ken Bohn Consulting
Keyes & Fox LLP
Leviton Manufacturing Co., Inc.

Los Angeles County Integrated Waste Management Task Force
MRW & Associates
Manatt Phelps Phillips
Marin Energy Authority
McKenzie & Associates

Modesto Irrigation District
NLine Energy, Inc.
NRG Solar

OnGrid Solar
Pacific Gas and Electric Company
Peninsula Clean Energy

Pioneer Community Energy

Public Advocates Office

Redwood Coast Energy Authority
Regulatory & Cogeneration Service, Inc.
SCD Energy Solutions
San Diego Gas & Electric Company

SPURR
San Francisco Water Power and Sewer
Sempra Utilities

Sierra Telephone Company, Inc.
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
Utility Cost Management
Utility Power Solutions
Water and Energy Consulting Wellhead Electric Company
Western Manufactured Housing Communities Association (WMA)
Yep Energy