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

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

RE: 2019 DPAG/DIDF

QUESTION 01

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

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

ANSWER 01

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

QUESTION 02

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

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

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

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

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

ANSWER 02

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

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

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

The four reliability needs are described as follows:

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

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

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

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

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

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

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

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

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

QUESTION 03

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

ANSWER 03

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

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

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

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

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

Cholame beyond X14:

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

Cholame Substation:

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

Templeton 2109 beyond R78:

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

QUESTION 04

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

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

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

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

ANSWER 04

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

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

As context, PG&E provided the 2- to 3-year time frame in response to data requests from Energy Division in the Estrella PTC proceeding regarding if and when PG&E would construct a 70-kV line between proposed Estrella Substation and existing Cholame Substation. In a data request dated June 27, 2017, Energy Division asked PG&E to "[d]iscuss the timing of future plans to connect existing Cholame Substation to the proposed Estrella Substation with a transmission line to better serve the Cholame DPA." PG&E responded on August 28, 2017, that "[t]he timing is unknown, but the proposed project provides the opportunity to add an additional transmission line to Cholame Substation in the future to create a looped circuit to improve reliability and operational

flexibility." In a subsequent data request dated February 27, 2018, Energy Division asked PG&E: "[i]f the Estrella Substation is constructed, what is a reasonable timeframe to assume that a 70-kV line to Cholame Substation would be constructed." PG&E responded on May 2, 2018 that "Section IV.B in the Updated Appendix G provides a reasonable timeframe to assume that a 70-kV line to existing Cholame Substation will be constructed. This estimate is preliminary and subject to change." Section IV.B in the Updated Appendix G contains the "2 to 3 year" statement quoted above. Thus, the context for this statement makes clear that the timing for such a 70-kV line is unknown and that the 2 to 3 year timeframe was provided at Energy Division's request for information to use in their CEQA analysis for the project. PG&E did not include the time needed to seek CAISO approval or a Permit to Construct from the CPUC in the 2 to 3 year timeframe, which in retrospect may have created confusion.

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

QUESTION 05

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

ANSWER 05

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

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

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

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

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

QUESTION 06

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

ANSWER 06

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

QUESTION 07

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

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

ANSWER 07

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

QUESTION 08

a. Table 2, below, shows a screen capture from the draft, updated PG&E 2019 GNA/DDOR filing (not yet refiled). The draft update still has discrepancies. For example, The GNA indicates that **San Miguel Bank 1** need reaches 1.68MW (2023) in the five-year planning window, not 3.6MW.
b. In addition, **Templeton Bank 3** exceeds it's rating by only 0.12 MW (2022) and not 1.1MW. Based on this low exceedance, which does not occur in 2023, it appears that Templeton Bank 3 should not be included as an Estrella Planned Investment capacity need at all.

ANSWER 08

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

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

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

   The peak projected load for San Miguel Bank 1 within the 5-year forecast is 19.1 MW in 2023, a 3.26 MW deficiency when evaluated against the summer normal capability of San Miguel Bank 1. The GNA reported the summer normal capacity of San Miguel Bank 1 as 17.42 MW, which is the re-rated capability of the

transformer bank, not the summer normal capability. Therefore, the GNA reports a deficiency of 1.68 MW against the 17.42 MW re-rate.

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

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

QUESTION 09

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

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

ANSWER 09

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

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

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

QUESTION 10

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

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

ANSWER 10

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

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

Hypothetical 2022 Estrella, Prioritization Metrics and Rankings

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

Hypothetical 2022 Estrella, Basis for Prioritization Metrics

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

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

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

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

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

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

QUESTION 11

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

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

ANSWER 11

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

QUESTION 12

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

ANSWER 12

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

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

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

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

The following distribution line work would also be needed:

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

QUESTION 13

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

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

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

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

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

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

ANSWER 13

This question is not applicable to PG&E.

QUESTION 14

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

ANSWER 14

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

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

QUESTION 15

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

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

ANSWER 15

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

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

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

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

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

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

QUESTION 16

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

ANSWER 16

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

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

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

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

QUESTION 17

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

ANSWER 17

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

QUESTION 18

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

ANSWER 18

This question is not applicable to PG&E.