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Exhibit No.: PGE-2  
Date: July 17, 2020  
Witness(es): Various

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**PACIFIC GAS AND ELECTRIC COMPANY**

**2021 ENERGY RESOURCE RECOVERY ACCOUNT AND  
GENERATION NON-BYPASSABLE CHARGES FORECAST AND  
GREENHOUSE GAS FORECAST REVENUE RETURN AND  
RECONCILIATION**

**SUPPLEMENTAL TESTIMONY**

**PUBLIC VERSION**

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PACIFIC GAS AND ELECTRIC COMPANY  
2021 ENERGY RESOURCE RECOVERY ACCOUNT AND GENERATION  
NON-BYPASSABLE CHARGES FORECAST AND GREENHOUSE GAS  
FORECAST REVENUE RETURN AND RECONCILIATION  
SUPPLEMENTAL TESTIMONY

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1                                   **PACIFIC GAS AND ELECTRIC COMPANY**  
2                                   **2021 ENERGY RESOURCE RECOVERY ACCOUNT AND**  
3                                   **GENERATION NON-BYPASSABLE CHARGES FORECAST AND**  
4                                   **GREENHOUSE GAS FORECAST REVENUE RETURN AND**  
5                                   **RECONCILIATION**  
6                                   **SUPPLEMENTAL TESTIMONY**

7   **A. Introduction**

8           Pacific Gas and Electric Company (PG&E) submits to the California Public  
9           Utilities Commission (CPUC or Commission) and the parties to this proceeding  
10          Supplemental Testimony (July Supplement) to PG&E's Prepared Testimony to  
11          its 2021 Energy Resource Recovery Account (ERRA) and Generation  
12          Non-Bypassable Charges Forecast and Greenhouse Gas (GHG) Forecast  
13          Revenue Return and Reconciliation Application (Application), served on July 1,  
14          2020 (Prepared Testimony). As further described in PG&E's Prepared  
15          Testimony, PG&E discovered an error in the electric load forecast during the  
16          final quality assurance associated with PG&E's Prepared Testimony.

17          In this July Supplement, PG&E: (1) provides detail concerning PG&E's  
18          electric load forecast errors, including corrections to Chapter 2 of PG&E's  
19          Prepared Testimony concerning the Sales and Peak Demand Forecast; (2)  
20          describes the impact of PG&E's correction on certain revenue requirements  
21          presented in PG&E's Prepared Testimony; (3) corrects certain tables provided in  
22          its Prepared Testimony impacted by the load forecast errors; and (4) corrects  
23          other minor errors discovered in its Prepared Testimony.

24          PG&E will serve parties to this proceeding with further supplemental  
25          testimony and supporting workpapers for PG&E's rate request presented in  
26          Chapter 19 of PG&E's Prepared Testimony on August 14, 2020.

27   **B. Electric Load Forecast Errors: Description and Correction**

28          The total electric load forecast provided in PG&E's Prepared Testimony  
29          contained an error that resulted in the understatement of Community Choice  
30          Aggregation (CCA) load and the overstatement of PG&E bundled load. PG&E  
31          initially determined that the total load forecast was not erroneous, but CCA load  
32          was understated and bundled load was overstated by approximately 1,000  
33          gigawatt hours (GWh). Due to the timing of the discovery of the error, PG&E's

1 Application and Prepared Testimony identified certain information subject to  
2 correction in this July Supplement. In this section, PG&E describes the electric  
3 load forecast error and additional corrections to Chapter 2 of PG&E's Prepared  
4 Testimony concerning the Sales and Peak Demand Forecast identified during  
5 the preparation of this July Supplement.

6 **1. Error Related to Electric Load Assignment Between Bundled and**  
7 **Departing Load**

8 To prepare the electric load forecast associated with PG&E's Prepared  
9 Testimony, PG&E conducts meet-and-confer activities and information  
10 exchanges with CCAs in PG&E's service territory. In preparing the electric  
11 load forecast following the meet-and-confer process, PG&E combines  
12 multiple CCA load forecasts with other load forecast drivers to produce the  
13 total forecast. However, PG&E discovered that the forecasted expansion for  
14 one of the CCAs was inadvertently omitted and therefore the corresponding  
15 CCA load was incorrect. The final numbers are shown in line 11 of Table 2-  
16 2 and lines 14 through 27 of Table 2-3 of PG&E's Prepared Testimony. The  
17 July Supplement corrects these entries among others.

18 The corrected version of PG&E's 2021 electric load forecast  
19 appropriately assigns electric load associated with that expansion to CCA  
20 load, increasing the total annual CCA load, visible at the right of line 27 of  
21 Table 2-3, to 36,303 GWh. Combined with the correction of other errors,  
22 described below in Section B2, this results in a corresponding decrease to  
23 forecast total annual bundled customer load of 1,171 GWh as reflected in  
24 line 29 of Table 2-3. The following textual corrections are also required in  
25 Chapter 2 of the Prepared Testimony.

Page	Line	Delete	Replace with	Reason
2-1	20	10 percent	14 percent	Correction to the CCA forecast
2-2	2	59 percent	60 percent	Correction to the CCA forecast

26 **2. Additional Errors Identified in the Energy and Peak Load Calculations**

27 While going through the changes and recalculations required to update  
28 Table 2-3 for this July Supplement, PG&E discovered additional errors in its  
29 Prepared Testimony related to the energy and peak load values provided in  
30 Table 2-3. PG&E describes and corrects those errors here.

1 In Table 2-3 of PG&E's Prepared Testimony, PG&E inadvertently  
2 utilized two different assumptions to shape the annual forecast into monthly  
3 values rather than a single set of assumptions: (1) a draft version of the  
4 shaping assumptions was used to prepare the component (i.e., CCA, direct  
5 access, and bundled) peak load values; and (2) the final version of monthly  
6 shaping assumptions was used to prepare the monthly energy values.  
7 PG&E corrected Table 2-3 by applying the final version of monthly shaping  
8 assumptions consistently for both the peak load and energy values. Finally,  
9 PG&E ensured that the monthly energy values summed to the annual  
10 energy total.

11 Second, Bay Area Rapid Transit (BART) load was inadvertently included  
12 in the peak load calculation presented in PG&E's Prepared Testimony. As  
13 explained in Chapter 2 of PG&E's Prepared Testimony, PG&E's total peak  
14 requirement is net of BART demand. Accordingly, in PG&E's corrected  
15 Table 2-3, PG&E removes BART demand from the peak load calculations.  
16 The BART correction caused a reduction of about 50 megawatt (MW) in  
17 each month in line 40 (retail peak).

18 Finally, PG&E corrected the "UFE, Transmission & Distribution Losses"  
19 in line 28 of Table 2-3. Correction of this error caused a reduction of about  
20 125 GWh over the full year.

### 21 **3. Impact of Corrections**

22 Apart from the correction to the CCA load, the net impact of the other  
23 changes is relatively minor – less than an 80 GWh reduction in the total  
24 annual sales requirement. However, the correction to the monthly shaping  
25 assumptions alters the peak values in a manner where the monthly  
26 adjustment is not constant over the year. As such, the combined impact of  
27 all the corrections described above result in monthly changes in peak values  
28 for bundled customers ranging between approximately 80 MW and 600 MW.

29 Correcting the load forecast errors results in changes to tables  
30 throughout PG&E's Prepared Testimony. The following tables were  
31 impacted by the load forecasting errors and are corrected in this July  
32 Supplement. Table 18-1 is identical to Table 1-1 and has not been included  
33 separately.

**TABLES IN PG&E'S PREPARED TESTIMONY IMPACTED BY THE  
LOAD FORECASTING ERRORS AND CORRECTED IN THIS JULY SUPPLEMENT**

Line No.	Page No.	Table No.	Table Title
1	1-3	1-1	Summary Of 2021 Forecast Energy Procurement Revenue Requirements
2	2-15	2-2	2021 Departed Load Sales Estimated By Category
3	2-19, 2-20	2-3	2021 Energy and Peak Demand Requirements
4	3-9, 3-10, 3-11	3-1	2021 Capacity Balance
5	3-12, 3-13	3-2	2021 Energy Requirements
6	3-14, 3-15	3-3	2021 Procurement Costs
7	7-10	7-3	2021 Procurement Costs
8	12-3	12-1	2021 ERRA Forecast Revenue Requirement
9	15-9	15-1	Confidential Annual GHG Emissions and Associated Costs (Template D-2)
10	15-10	15-2	Illustrative Annual GHG Emissions and Associated Costs (Template D-2)
11	18-4	18-1	Same presentation as Table 1-1, above Summary Of 2021 Forecast Energy Procurement Revenue Requirements
12	Appendix A	AppA-3	Table of Greenhouse Gas History of Revenue, Costs, and Emissions Intensity (Template D-5)

**C. Impact to Revenue Requirements**

PG&E's correction to the load forecast results in an increase in CCA load and a decrease in bundled customer load. Given that the correction has no impact on PG&E's forecasted supply portfolio positions, only the ERRA revenue requirement presented in PG&E's Application, Prepared Testimony, and PG&E's total request are reduced.<sup>1</sup> For this supplemental testimony, PG&E has incorporated changes reflecting the 1,171 GWh reduction in bundled customer energy demand. Specifically, PG&E's supplemental testimony reflects the lower forecasted energy and related costs from the California Independent System Operator that directly results from PG&E lower bundled customer energy demand.<sup>2</sup> The lower bundled load forecast results in a \$48.4 million reduction in the ERRA revenue requirement.

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<sup>1</sup> The Cost Allocation Mechanism (CAM), Ongoing Competition Transition Charge (CTC), Power Charge Indifference Adjustment (PCIA), and Tree Mortality Nonbypassable Charge (TMNBC) revenue requirements are not impacted by changes to departed or PG&E bundled customer sales.

<sup>2</sup> Residual resource adequacy (RA) and renewable portfolio standard (RPS) transactions will be updated as part of PG&E's November Update based on commercial activity since PG&E's Opening Testimony.

1 **D. Correcting the Discovery of Minor Errors in Prepared Testimony**

2 Since PG&E filed its Application, PG&E discovered minor errors to its  
3 Prepared Testimony, in addition to the load forecasting errors detailed  
4 previously. PG&E hereby submits the following corrections to its Prepared  
5 Testimony:

Page	Line	Delete	Replace with	Reason
4-2	17	fixed transportation cost	volumetric natural gas transportation rate	clarification
8-3	Table 8-1, line 1	[REDACTED]	[REDACTED]	Table 8-1 did not match Table 5-1, line 7, missing Qualifying Facility (QF)
8-3	Table 8-1, line 5	\$ (58,165)	\$ (58,185)	missing QF

6 PG&E includes updated tables impacted by the corrections presented in this  
7 supplement. Additionally, PG&E discovered that two Excel files supporting  
8 Chapter 2 were excluded from the public version of its workpapers. PG&E  
9 re-served the public workpapers to the A.19-06-001 service list on July 2, 2020.

10 **E. Updated Tables in Prepared Testimony**

11 The following tables appearing in PG&E's July 1, 2020 Prepared Testimony  
12 were impacted by the discovery of errors to the load forecast described  
13 previously and are shown below with corrected values.

14 **F. Conclusion**

15 PG&E has updated its load forecast to reflect corrections to the allocation of  
16 system load between bundled and departed-load customers. Only the ERRRA  
17 revenue requirement was impacted by the amended load forecast, resulting in a  
18 reduction of \$48.4 million relative to the original forecasted amount filed July 1,  
19 2020. This Supplement also includes minor corrections to the CAM revenue  
20 requirement. As a result, PG&E's total initial revenue requirement request is  
21 reduced. The restated revenue requirements for all rate categories are listed  
22 below in Table 1-1 and Table 18-1.

**TABLE 1-1 AND TABLE 18-1  
SUMMARY OF 2021 FORECAST ENERGY PROCUREMENT REVENUE REQUIREMENTS  
(THOUSANDS OF DOLLARS)**

Line No.		2021 Cost With Revenue Fees and <u>Uncollectibles</u> <sup>(b)</sup>	<u>2020 Year End</u> <u>Balance</u> <sup>(c)</sup>	Total 2021 Revenue <u>Requirement</u> <sup>(c)</sup>
		(A)	(B)	(C) = (A) + (B)
1	CAM <sup>(a)</sup> (Chapter 8)	181,416	84,934	\$266,350
2	PCIA (Chapter 9)	2,742,186	60,367	2,802,552
3	Ongoing CTC (Chapter 9)	45,955	(26,092)	19,863
4	TMNBC (Chapter 11)	37,354	35,265	72,619
5	ERRA (Chapter 12)	2,128,794	(287,352) <sup>(e)</sup>	1,841,442
6	PUBA (Chapter 14)	0	277,364	277,364
7	Revenue Requirement for Rate Setting	\$5,135,704	\$144,487	\$5,280,191
8	Less: UOG-Related Costs <sup>(d)</sup>	(2,522,491)		(2,522,491)
9	2021 ERRA Application Revenue Requirement Request	\$2,613,213	\$144,487	\$2,757,700

Notes:

(a) The CAM revenue requirement presented in Chapter 8 is recovered through the NSGC.

(b) Costs exclude GTSR Program Costs.

(c) The year-end balancing account balances recovered in rates through the AET, and or subsequent rate change advice letter.

(d) UOG-Related Costs in the revenue requirement components included in PCIA, ERRA and CAM are solely for rate-setting purposes, and PG&E does not request approval of these costs in this Application.

(e) The ERRA overcollection is the deferred revenue collected in generation rates because of capped departed PCIA rates. The offsetting amount is reflected in PUBA (line 6)

Totals may not add due to rounding.

**TABLE 2-2  
2021 DEPARTED LOAD SALES ESTIMATED BY CATEGORY (MWh)**

Line No.	Departing Load Category	Total DL	Ongoing CTC	PCIA	NSGC	Vintaged NSGC
1	Pre-2012 Transferred Municipal DL(a)	522,217	399,457	Exempt	Exempt	Exempt
2	2012 - 2019 Incremental TMDL(a)	122,847	122,847	Exempt	Exempt	122,847
3	Pre-2012 New Municipal DL(a)	219,622	0	Exempt	Exempt	Exempt
4	2012 - 2019 Incremental NMDL(a)	0	0	Exempt	Exempt	Exempt
5	Customer Generation DL(a)	9,403,920	696,048	Exempt	Exempt	N/A
6	New WAPA DL(a)	45,686	2,493	0	2,493	N/A
7	Split Wheeling DL(a)	6,527	6,527	0	6,527	N/A
8	Direct Access less Continuous D. 12-04-012	10,811,759	10,811,759	5,524,307	10,811,759	N/A
9	Continuous DA D. 12-04-012(a)	233,458	233,458	Exempt	233,458	N/A
10	Total Direct Access	11,045,217	11,045,217	5,524,307	11,045,217	N/A
11	CCA	36,303,391	36,303,391	36,303,391	36,303,391	N/A
12	<b>Total Departing Load</b>	<b>57,669,427</b>	<b>48,575,981</b>	<b>41,827,697</b>	<b>47,357,629</b>	<b>122,847</b>

(a) This item will be updated in PG&E's November update.

**TABLE 2-3  
2021 ENERGY (GWh) AND PEAK DEMAND (MW) REQUIREMENTS**

Line No.	Description	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
	<b>Energy Load (GWh)</b>													
1	Unmitigated Retail Sales													83,993
2	Conservation and Energy Efficiency													
3	Distributed Generation													
4	Solar													
5	CHP													
6	Fuel Cell & Other													
7	Electric Vehicles													
8	Electrification													
9	Retail Sales													78,322
10	Direct Access	(890)	(850)	(873)	(904)	(914)	(935)	(1,003)	(1,039)	(984)	(920)	(878)	(855)	(11,045)
11	Community Choice Aggregation													
12	Marin Clean Energy													
13	Sonoma Clean Power													
14	Clean Power San Francisco													
15	Peninsula Clean Energy													
16	Silicon Valley Clean Energy													
17	Redwood Coast Energy Authority													
18	Pioneer Community Energy													
19	Monterey Bay Community Power													
20	East Bay Community Energy													
21	San Jose Clean Energy													
22	Valley Clean Energy													
23	King City Community Power													
24	Butte Choice Energy													
25	Community Choice Aggregation Total	(2,972)	(2,726)	(2,804)	(2,714)	(2,865)	(3,078)	(3,328)	(3,393)	(3,150)	(3,021)	(3,018)	(3,232)	(36,303)
26	UFE, Transmission & Distribution Losses													2,774
27	Total Requirement													33,748
28	Retail Sales excludes BART energy requirements.													
29														
30														

**TABLE 2-3  
2021 ENERGY (GWh) AND PEAK DEMAND (MW) REQUIREMENTS  
(CONTINUED)**

Line No.	Peak Load (MW)	2021 PEAK REQUIREMENTS (MW)											
31	Unmitigated Retail Peak	(1,370)	(1,479)	(1,443)	(1,644)	(1,543)	(1,638)	(1,662)	(1,726)	(1,777)	(1,512)	(1,572)	(1,291)
32	Conservation and Energy Efficiency	(6,188)	(6,085)	(5,588)	(5,855)	(6,124)	(7,276)	(7,322)	(7,409)	(7,404)	(6,472)	(6,316)	(6,439)
33	Distributed Generation												
34													
35													
36													
37	Electric Vehicles												
38	Electrification												
39	Battery Energy Storage												
40	Retail Peak with distribution losses												
41	Direct Access with distribution losses												
42	Community Choice Aggregation with distrib losses												
43	UFE & Transmission Losses	(169)	(171)	(177)	(191)	(240)	(272)	(279)	(270)	(255)	(221)	(182)	(182)
44	Demand Response												
45	Puget Sound Power & Light (Return)												
46	Total Requirement												
47	Retail Peak excludes BART demand requirements.												

**TABLE 3-1  
2021 CAPACITY BALANCE (MW)**

Line No.	Description	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	<b>Peak ERRA Load (MW)</b>												
1	PG&E Bundled Peak load Forecast												
2	CPUC 2021 RA Compliance Requirement Adjustment												
3	Peak Coincidence												
4	Reserve Requirement												
5	CAM, DR and other Adjustments												
6	<b>Total ERRA Capacity Requirement</b>												
7	<b>Capacity Supply (MW)</b>												
8	Cost Allocation Mechanism (CAM)												
9	Utility-Owned Generation												
10	UOG Energy Storage												
11	Post-2002 Contracted Resources												
12	Other Bilateral Contracts												
13	Non-CHP Fossil												
14	CHP Fossil												
15	QF												
16	Energy Storage												





**TABLE 3-2  
2021 ENERGY REQUIREMENTS  
(GWh)**

Line No.	Description	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1	<u>ERRA Energy Load (GWh)</u>													
2	Retail Sales													
3	Direct Access and CCA													
4	UFE, Transmission & Distribution Losses													
5	<b>Total ERRA Load Requirement</b>	3,862	3,576	3,678	3,618	3,779	4,014	4,331	4,433	4,134	3,941	3,896	4,087	47,349
6	<u>Energy Supply (GWh)</u>													
7	Cost Allocation Mechanism (CAM)													
8	Utility-Owned Generation													
9	Energy Storage													
10	Post-2002 Contracted Resources													
11	Other Bilateral Contracts													
12	Fossil Contracts - Non-CHP													
13	Fossil Contracts - CHP													
14	Energy Storage													
15	CF													
	<b>Total</b>													(2,774)
														(33,748)



**TABLE 3-2  
2021 ENERGY REQUIREMENTS  
(GWh)  
(CONTINUED)**

	4	3	2	2	3	3	4	5	6	5	6	5	4	6	5	4	5	49
38 Ongoing Competition Transition Charge (CTC)																		
39 Pre-2002 Contracted Resources																		
40 Irrigation District & Water Agency																		
41 MWD Eliv and a																		
42 Puget Sound Power & Light Contract (Net)																		
43 QF																		
44 Tree Mortality Non-Bypassable Charge (TMNBC)																		
45 Post-2002 Contracted Resources																		
46 RPS Eligible																		
47 RPS-Eligible Contracts	47	47	44	45	40	39	50	52	42	51	52	49	52	42	49	52	49	556
48 RPS-Eligible Contracts - Sales	(27)	(30)	(33)	(26)	(21)	(20)	(30)	(32)	(28)	(32)	(32)	(29)	(32)	(28)	(29)	(32)	(29)	(339)
49 RPS-Eligible Future Contracts	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
50 RPS-Eligible Future Sales	(19)	(18)	(11)	(19)	(20)	(19)	(20)	(20)	(14)	(19)	(20)	(20)	(20)	(14)	(20)	(20)	(20)	(217)
51 Modified Cost Allocation Mechanism (MCAM)																		
52 Post-2002 Contracted Resources																		
53 Other Bilateral Contracts																		
54 Energy Storage Future Contracts																		
55 Energy Resource Recovery Account (ERRA)																		
56 Post-2002 Contracted Resources																		
57 Other Bilateral Contracts																		
58 QF																		
59 Energy Storage																		
60 Utility-Owned Generation																		
61 Solar																		
62 Energy Storage																		
63 <b>Total Supply</b>	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Note: Totals may not add due to rounding.

**TABLE 3-3  
2021 PROCUREMENT COSTS  
(THOUSANDS OF DOLLARS)**

Line No.	Description	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1	Energy Supply / Demand Procurement Costs (\$)													
2	Cost Allocation Mechanism (CAM)													
3	Utility-Owned Generation													
4	Energy Storage													
5	Post-2002 Contracted Resources													
6	Other Bilateral Contracts													
7	Fossil Contracts - Non-CHP													
8	Fossil Contracts - CHP													
9	Energy Storage													
10	QF													
11	Power Charge Indifference Adjustment (PCIA)													
12	Utility-Owned Generation													
13	Nuclear													
14	Hydro													
15	Fossil													
16	Solar													
17	Fuel Cell													
18	Energy Storage													
19	Pre-2003 Contracted Resources													
20	QF													

**TABLE 3-3  
2021 PROCUREMENT COSTS  
(THOUSANDS OF DOLLARS)  
(CONTINUED)**

21	Post-2002 Contracted Resources
22	RFS Eligible
23	RFS-Eligible Contracts
24	RFS-Eligible Contracts - Sales
25	RFS-Eligible Future Contracts
26	RFS-Eligible Future Sales
27	Other Bilateral Contracts
28	Fossil Contracts - Non-CHP
29	Fossil Contracts - CHP
30	Large Hydro
31	Energy Storage
32	RA Contracts
33	RA Contracts - Sales
34	Non-RFS-Eligible Hydro Sale
35	Residual Capacity Sales
36	CAISO Costs (GMCs)
37	Ongoing Competition Transition Charge (CTC)
38	Pre-2002 Contracted Resources
39	Irrigation District & Water Agency
40	MWD Etiwanda
41	Puget Sound Power & Light Contract (Net)
42	CF
43	CAISO Costs (GMCs)



**TABLE 7-3  
2021 PROCUREMENT COSTS  
(THOUSANDS OF DOLLARS)**

Line No.	Description	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1	<u>CAISO Costs</u>													
2	Grid Management Charges													
3	CTC													
4	ERRA													
5	PCIA													
6	TMNBC													
7	Bundled Load Requirement (ERRA)													
8	Other Load (ERRA)													
9	<u>Interstate Gas Transportation Costs</u>													
10	Cost Allocation Mechanism (CAM)													
11	Post-2002 Contracted Resources													
12	Other Bilateral Contracts													
13	Fossil Contracts - Non-CHP													
14	Fossil Contracts - CHP													
15	Power Charge Indifference Adjustment (PCIA)													
16	Utility-Owned Generation													
17	Fossil													
	Fuel Cell													
18	Post-2002 Contracted Resources													
19	Other Bilateral Contracts													
20	Fossil Contracts - Non-CHP													
21	<b>Total Costs</b>													

Note: Totals may not add due to rounding.

**TABLE 8-1  
2021 CAM FORECAST REVENUE REQUIREMENT  
(THOUSANDS OF DOLLARS)**

Line No.	Description	Cost
1	CAM-eligible Contract Costs – Table 5-1, Line 7	[REDACTED]
2	CAM-eligible Contract Costs – Table 6-1, Line 8	
3	CAM-eligible UOG Costs	
4	Total CAM-eligible Contract and UOG Costs	\$237,565
5	CAISO Market Revenues	<u>(58,185)</u>
6	Net Capacity Costs	\$179,380
7	Revenue Fees and Uncollectibles (RF&U) @ 0.011349 <sup>(a)</sup>	<u>2,036</u>
8	CAM Revenue Requirement	\$181,416

(a) The RF&U factor of 0.011349 is from Advice Letter 4020-G/5389-E, effective January 1, 2019. This factor will be updated in the November Update if available.

Note: Totals may not add due to rounding.

**TABLE 12-1  
2021 ERRA FORECAST REVENUE REQUIREMENT  
(THOUSANDS OF DOLLARS)**

Line No.	Description	2021 Forecast
1	Energy Resource Recovery Account (ERRA)	
2	Bundled Load Energy Requirement (Table 7-3, Line 7)	
3	Utility-Owned Generation	
4	Energy Storage (Table 4-3, Line 5)	
5	Grid Management Charges (Table 7-3, Line 4)	
6	Other Load (Table 7-3, Line 8)	
7	Hedging (Table 7-1, Line 9)	
8	Collateral Interest Expense (Table 7-2, Line 3)	10,822
9	RA Contracts (Table 6-1, Line 41)	
10	Residual Capacity Purchases (Table 6-1, Line 42)	
11	IRP Procurement Track - PGE (Table 10-1, Line 2)	
12	ERRA GRC Costs	50,574
13	Resource RA and REC Market Benchmark Value (a)	
14	PCIA REC Value (from Table 9-3 calculations)	190,979
15	PCIA RA Value (from Table 9-3 calculations)	430,820
16	CTC REC Value (from Table 9-3 calculations)	2,856
17	CTC RA Value (from Table 9-3 calculations)	<u>18,522</u>
18	<b>Total Costs</b>	<b>2,104,905</b>
19	RF&U @ 0.011349 (b)	23,889
20	<b>Total RRQ</b>	<b>2,128,794</b>

Notes:

(a) RA and REC market benchmark values are calculated based on the NQC and Renewable Energy at the meter totals shown on lines 18, 20, 22, and 14, respectively, in Table 9-3. These values are multiplied by 1.06 and then multiplied by the appropriate benchmark adder (RA or RPS).

(b) The Revenue Franchise & Uncollectible (RF&U) factor of 0.011349 is extracted from Tier 1 AL 4020-G/5389-E, effective January 1, 2019.

Totals may not add due to rounding.

**TABLE 15-1  
CONFIDENTIAL ANNUAL GHG EMISSIONS AND ASSOCIATED COSTS  
(TEMPLATE D-2)**

Line No.	Description	2019		2020		2021				
		Forecast	Recorded	Final	Forecast	Recorded	Final	Forecast	Recorded	Final
1	<u>Direct GHG Emissions (MT CO2e)</u>									
2	Utility Owned Generation (UOG)									
3	Tolling Agreements									
4	Energy Imports (Specified)									
5	Energy imports (Unspecified)									
6	Qualifying Facility (QF) Contracts									
7	Contracts with Financial Settlement									
8	Subtotal									
9	<u>Indirect GHG Emissions (MT CO2e)</u>									
10	CAISO Market Purchases (Net Physical)									
11	Contract Purchases									
12	Subtotal									
13	<b>Total Emissions (MT CO2e)</b>									
14	<u>Proxy GHG Price (\$/MT) (a)</u>	16.33	17.29	17.28	17.78	17.78	17.78	16.80	-	-
15	<u>GHG Costs (\$)</u>									
16	Direct GHG Costs (b)									
17	Direct GHG Costs - Financial Settlement									
18	Indirect GHG Costs									
19	Previous Year's Forecast Reconciliation (Line 21)									
20	<b>Total Costs (\$)</b>	1,242,241	1,242,241	(229,481)	(4,858,020)	(1,458,828)	(1,847,720)	(1,847,720)	(4,479,661)	-
21	<u>Forecast Variance (\$)</u>	N/A	(78,093,722)	48,772,379	N/A	N/A	N/A	N/A	N/A	-

(a) The difference between PG&E's confidential 2020 forecast GHG price and the 2020 forecast GHG proxy price is less than five percent.  
(b) D.15-01-024 directs utilities to calculate recorded direct GHG Costs as the sum of each month's weighted average cost (WAC) of compliance instruments held in inventory multiplied by that month's actual GHG emissions. Recorded and Final Direct GHG Costs presented here are consistent with the requirements of D.15-01-024, including accounting true-ups and adjustments to reflect updated information.  
Note: Totals may not add due to rounding.

**TABLE 15-2  
ILLUSTRATIVE ANNUAL GHG EMISSIONS AND ASSOCIATED COSTS  
(TEMPLATE D-2)**

Line No.	Description	2019		2020		2021	
		Forecast	Recorded	Forecast	Recorded	Forecast	Recorded
1	Direct GHG Emissions (MT CO2e)						
2	Utility Owned Generation (UOG)						
3	Tolling Agreements						
4	Energy Imports (Specified)						
5	Energy imports (Unspecified)						
6	Qualifying Facility (QF) Contracts						
7	Contracts with Financial Settlement						
8	Subtotal						
9	Indirect GHG Emissions (MT CO2e)						
10	CAISO Market Purchases (Net Physical)						
11	Contract Purchases						
12	Subtotal						
13	<b>Total Emissions (MT CO2e)</b>	<b>(229,481)</b>	<b>(4,858,020)</b>	<b>(1,847,720)</b>	<b>(1,847,720)</b>	<b>(4,479,661)</b>	-
14	<u>Proxy GHG Price (\$/MT) (a)</u>	16.33	17.29	17.78	17.78	16.80	-
15	<b>GHG Costs (\$)</b>						
16	Direct GHG Costs (b)						
17	Direct GHG Costs - Financial Settlement						
18	Indirect GHG Costs						
19	Previous Year's Forecast Reconciliation (Line 21)						
20	<b>Total Costs (\$)</b>	<b>(3,747,426)</b>	<b>(83,975,954)</b>	<b>(30,604,997)</b>	<b>(25,626,126)</b>	<b>(21,887,347)</b>	-
21	<u>Forecast Variance (\$)</u>	N/A	(80,228,529)	53,370,957	N/A	N/A	-

(a) The difference between PG&E's confidential 2021 forecast GHG price and the 2021 forecast GHG proxy price is less than five percent.  
(b) D.15-01-024 directs utilities to calculate recorded direct GHG Costs as the sum of each month's weighted average cost (WAC) of compliance instruments held in inventory multiplied by that month's actual GHG emissions. Recorded and Final Direct GHG Costs presented here are consistent with the requirements of D.15-01-024, including accounting true-ups and adjustments to reflect updated information.  
Note: Totals may not add due to rounding.

**TABLE A-1  
TABLE OF GREENHOUSE GAS HISTORY OF REVENUE, COSTS, AND EMISSIONS INTENSITY (TEMPLATE D-5)**

Line No.	Description	Recorded 2014	Recorded 2015	Recorded 2016	Recorded 2017	Recorded 2018	Recorded 2019	Forecast 2020	Forecast 2021
					(\$000)				
1	Total GHG Revenues (Net available for customers) (a)	\$578,743	\$456,431	\$366,996	\$310,534	\$387,880	\$319,155	\$382,471	\$195,801
2	Total GHG Costs	\$199,628	\$212,062	\$164,735	\$125,738	\$62,723	-\$33,961	-\$25,616	-\$22,838
3	Emissions Intensity (b)	0.210	0.216	0.176	0.165	0.081	-0.030	-0.049	-0.133
					(MT CO <sub>2</sub> e/MWh)				

**Notes:**

(a) Line 1 is derived from Line 17 of Table 17-5.

(b) The emissions intensity shown here is calculated by dividing total GHG emissions reported on Line 13 of Tables 15-1 and 15-2 by the total energy load required to serve PG&E's bundled electricity customers for the corresponding year. The emissions intensity is not the same calculation as the CO<sub>2</sub> emissions rate reported by PG&E to The Climate Registry (TCR).









