Docket No.: A.23-06-001

Exhibit No.: CalCCA-03

Date: September 26, 2023

Sponsor/Witness: Eric Lee (SCE)

EXHIBIT CALCCA-03

Select Passages of Prepared Testimony from A.22-05-029
(PG&E's 2023 ERRA Forecast Case)

September 26, 2023

Application: 22-05-
(U 39 E)
Exhibit No.:
Date: May 31, 2022
Witness(es): Various

PACIFIC GAS AND ELECTRIC COMPANY

2023 ENERGY RESOURCE RECOVERY ACCOUNT AND GENERATION NON-BYPASSABLE CHARGES FORECAST AND GREENHOUSE GAS FORECAST REVENUE RETURN AND RECONCILIATION

PREPARED TESTIMONY

PUBLIC VERSION

PACIFIC GAS AND ELECTRIC COMPANY
2023 ENERGY RESOURCE RECOVERY ACCOUNT AND GENERATION NON-BYPASSABLE CHARGES FORECAST AND GREENHOUSE GAS FORECAST REVENUE RETURN AND RECONCILIATION
PREPARED TESTIMONY

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PACIFIC GAS AND ELECTRIC COMPANY

CHAPTER 11

POWER CHARGE INDIFFERENCE ADJUSTMENT AND ONGOING COMPETITION TRANSITION CHARGE

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 11
POWER CHARGE INDIFFERENCE ADJUSTMENT AND ONGOING COMPETITION TRANSITION CHARGE

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2. Energy

The energy included in the calculation of the total portfolio cost reflects the forecast generation that PG&E expects to sell into the California Independent System Operator Corporation (CAISO) market, as described in Chapter 3 and presented in Table 3-2.

3. Renewable Energy Credits

California Pub. Util. Code Sections 399.11-399.33 established a requirement that 60 percent of total retail sales of electricity in California be from eligible renewable energy resources by December 31, 2030. The renewable and environmental attributes associated with eligible RPS energy are recognized through a certificate issued by the Western Renewable Energy Generation Information System, commonly known as Renewable Energy Credits (REC).

As part of the RPS Program, PG&E is required to submit an Annual RPS Compliance Report to report the utility's progress towards reaching the RPS compliance requirements, as implemented by D.12-06-038, and subsequent decisions. Compliance with the RPS program is measured in eligible RECs retired towards RPS compliance and evaluated on a multi-year compliance period basis.

For 2023, as a result of the RPS energy allocations and/or sales ordered by D. 21-05-030 further described in Chapter 9, PG&E forecasts that its bundled customer Net Physical RPS Position (i.e, for 2023, forecast 2023 RPS-eligible generation less allocation and/or market offer activity) will be less than PG&E's RPS compliance target for 2023. As such, PG&E proposes a methodology to assign 2021 and 2022 RECs to meet its bundled customer 2023 RPS compliance target. As described below, PG&E's methodology for 2023 ratesetting is consistent with RPS compliance rules, which permit excess generation from a current RPS compliance period to be applied to PG&E's bundled customer 2023 RPS annual deficit.

a. Minimum Retained Requirement Volume

In D.20-02-047, addressing PG&E's 2020 ERRA Forecast Application, the Commission established that the annual RPS target quantities provided in D.11-12-020 for calculating the RPS compliance period requirement served as appropriate minimum quantities for PG&E to consider for its annual retained RPS volumes as part of the PABA true-up.[26] PG&E was ordered to record an accounting entry to reduce the PABA and increase the ERRA based on an estimate of PG&E's 2019 RPS shortfall. While D.11-12-020 established annual minimum quantities applicable to the third RPS compliance period in effect at the time D. 20-02-047 as issued, D.19-06-023 established minimum quantities for the current 2021-2024 compliance period.[27]

Table 11-2 below shows the total annual RPS generation volumes in the current RPS compliance period. In PG&E's 2021 and 2022 ERRA forecast proceedings, PG&E's ERRA revenue requirement was calculated to recover the full RPS market value associated with PG&E's forecast annual RPS generation volumes, net of forecasted third party sales. Column B of Table 11-2 shows the net physical RPS position for 2021 exceeds the minimum RPS requirement or annual RPS compliance target. This is also the case for the net physical RPS position forecast for 2022. Therefore, in these years, PG&E's annual RPS generation net of third-party sales exceeded any applicable annual minimum. Accordingly, no adjustment entry has been necessary for these years.

For 2023 ratesetting, an adjustment entry is necessary due to the VAMO mechanism ordered by D.21-05-030 and detailed in Chapter 9. PG&E forecasts that the impact from the allocation/and or market offer of its DL share of the PCIA-eligible portfolio will result in PG&E's 2023 net physical position being less than its annual RPS target established in D.19-06-023. Given the forecast deficit, the following sections describe the methodology PG&E proposes to apply for 2023 ratesetting to determine (1) how many additional RECs to apply for bundled

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26 D.20-02-047, p. 13-14. This minimum retained amount was reinforced in D.20-12-012, p. 5 (stating "thus, the Decision merely stated that PG&E should procure "no less than," i.e., a minimum of 31 percent of retail sales by 2019. (D.20-02-047 p. 13.) PG&E fails to show how this conclusion is either unlawful or incorrect.")

27 D.19-06-023, p. 11 OP 1 adopts RPS procurement quantity requirements for the years 2021 – 2024.

customer compliance as part of the PCIA revenue requirement calculation; and (2) how the value of those additional RECs utilized for bundled customer compliance will be allocated across PCIA vintages within the RPS compliance period.[28]

1) Methodology

Pursuant to Senate Bill (SB) 2 enacted in 2011, the legislature established multi-year compliance periods for RPS compliance beginning with 2011 through 2013.[29] The total quantity of RPS-eligible procurement required for a compliance period is referred to as the "procurement quantity requirement." D.11-12-020, approved by the Commission on December 1, 2011, set the RPS procurement quantity requirements for the first three RPS compliance periods, culminating in 2020. Pursuant to COL 6 in D.11-12-020, retail sellers are not required to demonstrate a specific quantity of procurement for any intervening year in a compliance period. Rather, as stated in COL 7, retail sellers are required to show compliance with the procurement quantity requirement for a compliance period by procuring the cumulative quantity of RPS-eligible resources required for that compliance period.[30] In other words, regardless of shortfalls in any particular year or years within a compliance period, retail sellers can demonstrate compliance with the procurement quantity requirement by procuring the cumulative quantity of RPS-eligible resources for that compliance period during any time throughout that compliance period. Therefore, should there be a shortfall in RPS-eligible

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[28] PG&E's methodology addresses the need for a tracking framework identified in D.20-02-047.

[29] Pursuant to Section 399.15(b)(1) of SB 2 "(1) Each retail seller shall procure a minimum quantity of eligible renewable energy resources for each of the following compliance periods: (A) January 1, 2011, to December 31, 2013, inclusive. (B) January 1, 2014, to December 31, 2016, inclusive. (C) January 1, 2017, to December 31, 2020, inclusive."

[30] COL 5 in D.11-12-020 established that reasonable progress for compliance periods 2014-2016 and 2017-2020 should be determined by means of quantitative targets for the intervening years. D.11-12-020 established the intervening year quantitative targets using a straight-line method and such straight-line method continued to apply in the RPS compliance targets established by D.19-06-023.

procurement for an intervening year in a compliance period, that shortfall can first be made up with excess procurement during other intervening years of that same compliance period.

The same RPS compliance period requirement methodology was established for post-2020 RPS compliance periods by SB 100 enacted in 2018 and implemented by the Commission in D.19-06-023. Like prior RPS compliance periods, a RPS procurement shortfall in one year can first be satisfied by prior year excess in the current compliance period. For 2023, PG&E can apply 2021 and 2022 RECs as both of those years are part of the same fourth RPS compliance period that spans from 2021 through 2024.

Given the interdependence of RPS compliance between intervening years in a particular RPS compliance period, PG&E proposes the following methodology to determine how many additional RECs generated prior to 2023 within the same compliance period are applied for bundled service customer compliance as part of the 2023 PCIA revenue requirement calculation and how those RECs will be allocated across PCIA vintages within the applicable RPS compliance period.

(1) For a year in which there is a net shortfall and the remaining surplus RPS balance from the prior year(s) within the applicable RPS compliance period is greater than the ERRA year shortfall, an accounting adjustment will be made only to those years.

(2) The adjustment will be weighted across the applicable RPS generation surplus years based on the remaining amount of surplus available for each year.

The proposed allocation methodology is consistent with PG&E's 2021 and 2022 ERRA Forecast applications where the ERRA revenue requirement included the full retained REC value of the RPS generation less forecasted RPS Sales for each year. Therefore, customers who were part of PG&E's bundled customer base in each ERRA year were charged for all surplus RPS generation (i.e., RPS generation which exceeds the imputed annual compliance obligation and forecast sales). It is precisely those customers that earlier procured surplus RPS generation who will benefit from an accounting adjustment for 2023 ratesetting. The following sections present the implementation of this methodology.

2) Historical Initial Annual Net RPS Positions

In order to determine how accounting adjustments will address PG&E's forecast 2023 RPS deficits, PG&E must establish whether surplus RPS generation within the same compliance period exists. To do so, a net available compliance period RPS quantity for each year within the compliance period must first be calculated. This information is presented in Table 11-2, with column A showing the delivery year, which also represents the applicable ERRA Forecast year. Columns B and C include the net physical RPS position and PG&E bundled sales respectively. Initial data for 2021 comes from the bundled sales revenue accounting report and PG&E's 2021 Retained RPS tracker. This data will be updated in the Fall Update based on the data from PG&E's 2021 RPS Compliance Report. RPS generation for 2022 includes both actual RPS generation as well as forecasted data. Forecasted RPS generation data for part of 2022 and all of 2023 is calculated using PG&E's RPS stochastic forecasting model.[31] More details on this model and how generation forecasts are calculated can be found below.

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31 Consistent with the RPS Stochastic Model used in PG&E's Final 2021 RPS Procurement Plan.

TABLE 11-2
ANNUAL AVAILABLE COMPLIANCE PERIOD RPS GENERATION

Line No.	(A) Delivery Year	(B) Net Physical RPS Position[b] (MWh)	(C) Bundled Sales (MWh)	(D) Annual RPS Compliance Target (%)	(E) = (C * D) Annual RPS Compliance Target (MWh)	(F) = (B – E) Net Available Compliance Period RPS Generation (MWh)
1	2021[a]	17,118,575	33,149,379	35.8%	11,850,903	5,267,672
2	2022	13,288,204	27,725,857	38.5%	10,674,455	2,613,749

(a) Values for delivery year 2021 will be updated during PG&E's 2023 ERRA Forecast Application Fall Update based on PG&E's final 2021 RPS compliance report.

(b) Net Physical RPS position is RPS generation less RPS Sales.

Columns D and E include the annual RPS compliance target percentages and quantities respectively that need to be met by PG&E. The quantities included in Table 11-2 reflect rules and requirement quantities applicable to the current RPS compliance period, as laid out in D.19-06-023.[32] In D.19-06-023, the Commission maintained RPS target quantities that are ultimately based on a straight-line trend to reach each compliance period's RPS target.

With data captured annually for recorded RPS generation, Bundled Sales and RPS requirement targets, the net available compliance period RPS generation quantity in each year can be calculated by subtracting column E from column B. The next section details how the net available compliance period RPS generation quantities from Table 11-2 have been adjusted for any prior minimum retained RPS entries.

3) Historical Minimum RPS Entries

As referenced above, the CPUC established the minimum retained RPS requirement in D.20-02-047, with 2019 being the first effective year of this requirement. In order to satisfy this requirement for 2019, PG&E recorded accounting entries crediting

32 D.12-06-038: Decision Setting Compliance Rules for the RPS Program. https://docs.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/169704.pdf.

earlier PCIA vintages through PABA. For 2021 and 2022, no minimum retained RPS entries were necessary as PG&E's bundled RPS position exceeded the annual target in each of those years.

TABLE 11-3
COMPLIANCE PERIOD 4 MINIMUM RETAINED RPS ENTRIES

Line No.	(A) Delivery/Vintage Year	(B) Net Available Compliance Period RPS Generation (MWH)	(C) Applied Prior Year Minimum RPS Entry	(D) Adjusted Net RPS Position
1	2021	5,267,672	0[(a)]	5,267,672
2	2022	2,613,749	0[(a)]	2,613,749
3	Total	7,881,421	0	7,881,421

(a) No minimum retained RPS entry was needed related to 2021 and 2022 since in both years RPS generation exceeded the respective annual RPS targets resulting in a surplus.

Following the methodology described above, column E in Table 11-3 provides the adjusted net RPS position for each applicable year by accounting for all prior year minimum RPS entries (column C). The adjusted net RPS position then serves as the basis for weighting the forecasted minimum RPS entry for 2023 presented below.

4) 2023 RPS Position

To determine the forecasted Net RPS Position for 2023,[33] PG&E uses the results from its RPS stochastic model, which it utilizes for bundled RPS position planning in the annual RPS Plan Proceeding.[34] Basing the 2023 Net RPS Position on PG&E's stochastic model aligns with how PG&E manages its bundled RPS position planning and incorporates expected impacts from

33 As noted in this section, PG&E makes use of its RPS stochastic model to forecast its RPS position for 2023 as well as part of 2022.

34 The RPS Stochastic Model used here is consistent with the model described in Section VII of PG&E's Final 2021 RPS Procurement Plan.

uncertainties such as renewable curtailment.[35] PG&E presents the forecasted 2023 net physical RPS position, bundled sales, RPS compliance target, and net RPS deficit in Table 11-4, which shows a forecasted short position of 4,932,817 MWh in 2023. This deficit primarily results from the projected impact of the VAMO sales presented in Chapter 9. The next section presents the minimum retained RPS entry results for 2023 based on the methodology described below.

TABLE 11-4
2023 RPS POSITION SUMMARY

Line No.	(A) Delivery Year	(B) Net Physical RPS Position[(a)] (MWh)	(C) Bundled Sales (MWh)	(D) Annual RPS Compliance Target (%)	(E) = (C * D) Annual RPS Compliance Target (MWh)	(F) = (B - E) Net RPS Deficit (MWh)
1	2023	6,903,847	28,694,941	41.3%	11,836,663	(4,932,817)

(a) Net physical RPS position is RPS generation less RPS Sales.

5) Determination of Additional Retained RECs

Following the methodology laid out above, the minimum retained RPS entry for 2023 will credit PCIA vintages 2021 and 2022 based on their weighted share of the cumulate excess across those years and debit ERRA for 4,932,817 MWh. The results of the forecasted entries are shown in Table 11-5 below.

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35 The stochastic model specifically employs a Monte Carlo simulation of risks. A Monte Carlo simulation is a computational algorithm commonly used to account for uncertainty in quantitative analysis and decision making. A Monte Carlo simulation provides a range of possible outcomes, the probabilities they will occur and the distributions of possible outcome values.

TABLE 11-5
2023 MINIMUM RETAINED RPS ENTRY

Line No.	(A) Delivery Year	(B) Pre-2023 Adjusted Net RPS Position	(C) Minimum 2023 Entry	(D) = (B + C) Post-2023 Adjusted Net RPS Position
1	2021	5,267,672	(3,296,926)	1,907,746
2	2022	2,613,749	(1,635,891)	977,858
3	2023	(4,932,817)	4,932,817	0
4	Total	2,948,604	0	2,948,604

PG&E will update the forecasted 2023 minimum retained RPS entry in its Fall Update based on updated portfolio forecast assumptions. The entries associated with the 2023 minimum retained RPS will be true-ed up through the applicable balancing accounts and presented as part of PG&E's 2023 ERRA Compliance Review Application.

F. Market Price Benchmark

1. Background

MPBs are used to calculate the Ongoing CTC and the PCIA indifference amounts described in this testimony. The indifference amounts are derived by taking the difference between the total cost forecast of the portfolio of resources and the market value forecast of those resources to determine the above-market costs associated with the portfolio. The market value for the portfolio is determined by multiplying the Commission-approved MPBs by the applicable volumes from the portfolio to determine an equivalent market value for the generation portfolio.

The MPB calculation was originally adopted in D.06-07-030 and modified in D.07-01-025, D.11-12-018, and Res.E-4475.[36] A revised methodology to calculate two components of the MPB, the RPS and RA Adders, was adopted in D.18-10-019 and D.19-10-001. D. 22-01-023, OP1 stated that the Commission's Energy Division shall calculate the components of the MPB and make them available by October 1 of each

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36 See Appendix 1 of D.06-07-030.

TABLE 11-7
IOU TOTAL PORTFOLIO SUMMARY
PURSUANT TO D.17-08-026, AND MODIFIED TO COMPLY WITH OP 3 OF D.18-10-019 AND D.21-03-051

Line No.		Ongoing CTC-Eligible Portfolio	PPCP	UOG Legacy and Vintaged PCIA Portfolio														IOU Total Portfolio
				UOG Legacy	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	
1.	CRS Eligible Portfolio Costs ($000)	$169,094	$2,407	$1,990,060	$1,705,216	$279,977	$88,931	$106,635	$26,291	$2,882	$6,663	$1,120	$5,334	($5)	$4	$692	$30,844	$4,416,147
2.	CRS Eligible Non-Renewable Supply at Generation Meter (GWh)	1,628	37	25,192	9,532	-1,360	-13	137	-3	0	23	0	0	0	0	0	0	35,173
3.	CRS Eligible Renewable Supply at Generation Meter (GWh)	116	12	700	2,356	1,823	616	739	450	54	86	27	115	0	0	0	25	7,119
4.	CRS Eligible Total Net Qualifying Capacity (MW)																	
5.	CRS Eligible System NQC (System only, No flex or local)	114	1	1,140	187	49	24	39	19	1	1	1	4	0	0	0	0	1,581
6.	CRS Eligible Local NQC (System and local, with or without flex)	222	4	1,907	1,552	102	27	234	4	3	10	0	77	0	0	9	2	4,154
7.	CRS Eligible Flexible NQC (System and flex only, No local)	0	0	371	920	0	0	0	0	0	0	0	0	0	0	0	781	2,072

To comply with D. 18-10-019, OP 3 and subsequent direction from the CPUC's Energy Division, PG&E, in October 2018, submitted revisions to the confidential version of PG&E's uniform common spreadsheet template for calculation of the PCIA rates. The table above reflects one of the worksheets included in the template.

TABLE 11-8
INDIFFERENCE CALCULATION INPUTS AND SOURCES
PURSUANT TO D.17 08 026, AND
MODIFIED TO COMPLY WITH OP 3 OF D.18-10-019 AND D.21-03-051

Line No.	Description	Source of Data	Value
1.	On Peak Energy Index ($/MWh)	Table 3-4	[redacted]
2.	Off Peak Energy Index ($/MWh)	Table 3-4	
3.	On Peak Load Weight (%)	2021 Recorded Bundled Load - On Peak Hours	39.9%
4.	Off Peak Load Weight (%)	2021 Recorded Bundled Load - Off Peak Hours	60.1%
5.	Load Weighted Average Price ($/MWh) [1]	Line 1 x Line 3 + Line 2 x Line 4	[redacted]
6.	Green/RPS Adder ($/MWh)	2022 authorized Benchmark	$13.70
7.	Green Benchmark ($/MWh)	Line 6 + Line 5	[redacted]
8.	System RA Benchmark ($/kW-Year)	2022 authorized Benchamrk ($6.03 kW-Month x 12)	$72.36
9.	Local RA Benchmark ($/kW-Year)	2022 authorized Benchamrk ($6.35 kW-Month x 12)	$76.20
10.	Flexible RA Benchmark ($/kW-Year)	2022 authorized Benchamrk ($6.41 kW-Month x 12)	$76.92
11.	Revenue Fee and Uncollectible Factor	Advice 4512-G/6373-E	0.010811

To comply with D. 18-10-019, OP 3 and subsequent direction from the CPUC's Energy Division, PG&E, in October 2018, submitted revisions to the confidential version of PG&E's uniform common spreadsheet template for calculation of the PCIA rates. The table above reflects one of the worksheets included in the template.

TABLE 11-9
INDIFFERENCE AMOUNT CALCULATION, PURSUANT TO D.17-08-026, AND MODIFIED TO COMPLY WITH OP 3 OF D.18-10-019 AND D.21-03-051

Line No.	Description	Equation	Unit	Ongoing CTC-Eligible	PPCP	UOG Legacy and Vintaged PCIA: UOG Legacy	2009	2010	2011	2012	2013	2014	2015
	Cost of Portfolio												
1.	Portfolio Total Cost	Table 11-7, Line 1	$000	$169,094	$2,407	$1,990,060	$1,705,216	$279,977	$88,931	$106,635	$26,291	$2,882	$6,663
2.	CRS Eligible Non-Renewable Supply at Generation Meter	Table 11-7, Line 2	GWh	1,628	37	25,192	9,532	-1,360	-13	137	-3	0	23
3.	CRS Eligible Renewable Supply at Generation Meter	Table 11-7, Line 3	GWh	116	12	700	2,356	1,823	616	739	450	54	86
4.	CRS Eligible System NQC	Table 11-7, Line 5	MW	114	1	1,140	187	49	24	39	19	1	1
5.	CRS Eligible Local NQC	Table 11-7, Line 6	MW	222	4	1,907	1,552	102	27	234	4	3	10
6.	CRS Eligible Flexible NQC	Table 11-7, Line 7	MW	0	0	371	920	0	0	0	0	0	0
7.	**Portfolio Unit Cost**	**Line 1 / (Line 2 + Line 3)**	**$/MWh**	**$97**	**$49**	**$77**	**$143**	**$604**	**$148**	**$122**	**$59**	**$54**	**$61**
8.	**Market Value of Portfolio**												
9.	**Market Value of Brown Portfolio**												
10.	Non-Renewable Energy	Line 2	GWh	1,628	37	25,192	9,532	-1,360	-13	137	-3	0	23
11.	Weighted Average Brown Benchmark	Table 11-8, Line 5	$/MWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
12.	**Market Value of Brown Portfolio**	**Line 10 x Line 11**	**$000**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
13.	**Market Value of Green Portfolio**												
14.	Renewable Energy	Line 3	GWh	116	12	700	2,356	1,823	616	739	450	54	86
15.	Weighted Average Green Benchmark	Table 11-8, Line 7	$/MWh	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
16.	**Market Value of Green Portfolio**	**Line 14 x Line 15**	**$000**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
17.	**Capacity Adder**												
18.	Average Monthly System NQC	Line 4	MW	114	1	1,140	187	49	24	39	19	1	1
19.	System RA Benchmark	Table 11-8, Line 8	$/kW-Year	$72.36	$72.36	$72.36	$72.36	$72.36	$72.36	$72.36	$72.36	$72.36	$72.36
20.	Average Monthly Local Area NQC	Line 5	MW	222	4	1,907	1,552	102	27	234	4	3	10
21.	Local RA Benchmark	Table 11-8, Line 9	$/kW-Year	$76.20	$76.20	$76.20	$76.20	$76.20	$76.20	$76.20	$76.20	$76.20	$76.20
22.	Average Monthly Flexible NQC	Line 6	MW	0	0	371	920	0	0	0	0	0	0
23.	Flexible RA Benchmark	Table 11-8, Line 10	$/kW-Year	$76.92	$76.92	$76.92	$76.92	$76.92	$76.92	$76.92	$76.92	$76.92	$76.92
24.	**Market Value of Capacity**	**Sum (Lines 18 x 19, 20 x 21, 22 x 23)**	**$000**	**$25,206**	**$421**	**$256,417**	**$202,538**	**$11,344**	**$3,765**	**$20,663**	**$1,683**	**$298**	**$839**
25.	**Portfolio Market Value**	**Line 12 + Line 16 + Line 24**	$000	**$134,703**	**$3,611**	**$1,867,736**	**$970,214**	**$64,994**	**$49,475**	**$84,956**	**$35,523**	**$4,344**	**$8,767**
26.	**Indifference Amount**												
27.	**Portfolio Total Cost**	**Line 1**	$000	**$169,094**	**$2,407**	**$1,990,060**	**$1,705,216**	**$279,977**	**$88,931**	**$106,635**	**$26,291**	**$2,882**	**$6,663**
28.	**Portfolio Market Value**	**Line 25**	$000	**$134,703**	**$3,611**	**$1,867,736**	**$970,214**	**$64,994**	**$49,475**	**$84,956**	**$35,523**	**$4,344**	**$8,767**
29.	**Total Indifference Amount (Unadjusted)**	**Line 27 - Line 28**	$000	**$34,391**	**($1,204)**	**$122,324**	**$735,002**	**$214,983**	**$39,456**	**$21,678**	**($9,232)**	**($1,462)**	**($2,104)**
30.	**DWR Revenue Requirement**		$000										
31.	**PCIA Minimum Retained REC Value Adjustment**	**Table 11-5 x (Line 15 - Line 11)**	$000										
32.	**Adjusted Indifference Amount**	**Sum (Lines 29:31)**	$000	**$34,391**	**($1,204)**	**$122,324**	**$735,002**	**$214,983**	**$39,456**	**$21,678**	**($9,232)**	**($1,462)**	**($2,104)**
33.	**Revenue Franchise Fees & Uncollectibles (RF&U)**	**Advice 4512-G/6373-E**	$000	**$372**	**($13)**	**$1,322**	**$7,946**	**$2,324**	**$427**	**$234**	**($100)**	**($16)**	**($23)**
34.	**Adjusted Indifference Amount with RF&U**	**Line 32 + Line 33**	$000	**$34,763**	**($1,217)**	**$123,647**	**$742,949**	**$217,307**	**$39,883**	**$21,913**	**($9,332)**	**($1,477)**	**($2,126)**
35.	**Cummulative Adjusted Indifference Amount with RF&U**		$000	**$34,763**	**($1,217)**	**$123,647**	**$866,596**	**$1,083,903**	**$1,123,786**	**$1,145,698**	**$1,136,366**	**$1,134,889**	**$1,132,762**

To comply with D. 18-10-019, OP 3 and subsequent direction from the CPUC's Energy Division, PG&E, in October 2018, submitted revisions to the confidential version of PG&E's uniform common spreadsheet template for calculation of the PCIA rates. Lines 1 through 35 of the above table reflects thos included in one of the worksheets of the template.

TABLE 11-9
INDIFFERENCE AMOUNT CALCULATION, PURSUANT TO D.17-08-026, AND MODIFIED TO COMPLY WITH OP 3 OF D.18-10-019 AND D.21-03-051
(CONTINUED)

Line No.	Description	Equation	Unit	UOG Legacy and Vintaged PCIA 2016	2017	2018	2019	2020	2021	2022
	Cost of Portfolio									
1.	Portfolio Total Cost	Table 11-7, Line 1	$000	$1,120	$5,334	-$5	$4	$692	$30,844	
2.	CRS Eligible Non-Renewable Supply at Generation Meter	Table 11-7, Line 2	GWh	0	0	0	0	0	0	
3.	CRS Eligible Renewable Supply at Generation Meter	Table 11-7, Line 3	GWh	27	115	0	0	0	25	
4.	CRS Eligible System NQC	Table 11-7, Line 5	MW	1	4	0	0	0	0	
5.	CRS Eligible Local NQC	Table 11-7, Line 6	MW	0	77	0	0	9	2	
6.	CRS Eligible Flexible NQC	Table 11-7, Line 7	MW	0	0	0	0	0	781	
7.	**Portfolio Unit Cost**	**Line 1 / (Line 2 + Line 3)**	**$/MWh**	**$42**	**$46**	**$0**	**$0**	**$0**	**$1,239**	**$0**
8.	**Market Value of Portfolio**									
9.	**Market Value of Brown Portfolio**									
10.	Non-Renewable Energy	Line 2	GWh	0	0	0	0	0	0	0
11.	Weighted Average Brown Benchmark	Table 11-8, Line 5	$/MWh	[redacted]						
12.	**Market Value of Brown Portfolio**	**Line 10 x Line 11**	**$000**							
13.	**Market Value of Green Portfolio**									
14.	Renewable Energy	Line 3	GWh	27	115	0	0	0	25	0
15.	Weighted Average Green Benchmark	Table 11-8, Line 7	$/MWh	[redacted]						
16.	**Market Value of Green Portfolio**	**Line 14 x Line 15**	**$000**							
17.	**Capacity Adder**									
18.	Average Monthly System NQC	Line 4	MW	1	4	0	0	0	0	0
19.	System RA Benchmark	Table 11-8, Line 8	$/kW-Year	$72.36	$72.36	$72.36	$72.36	$72.36	$72.36	$72.36
20.	Average Monthly Local Area NQC	Line 5	MW	0	77	0	0	9	2	0
21.	Local RA Benchmark	Table 11-8, Line 9	$/kW-Year	$76.20	$76.20	$76.20	$76.20	$76.20	$76.20	$76.20
22.	Average Monthly Flexible NQC	Line 6	MW	0	0	0	0	0	781	0
23.	Flexible RA Benchmark	Table 11-8, Line 10	$/kW-Year	$76.92	$76.92	$76.92	$76.92	$76.92	$76.92	$76.92
24.	**Market Value of Capacity**	**Sum (Lines 18 x 19, 20 x 21, 22 x 23)**	**$000**	**$77**	**$6,109**	**$0**	**$0**	**$699**	**$60,254**	**$0**
25.	**Portfolio Market Value**	**Line 12 + Line 16 + Line 24**	$000	**$2,088**	**$14,795**	**$0**	**$0**	**$699**	**$62,134**	**$0**
26.	**Indifference Amount**									
27.	**Portfolio Total Cost**	**Line 1**	$000	**$1,120**	**$5,334**	**($5)**	**$4**	**$692**	**$30,844**	**$0**
28.	**Portfolio Market Value**	**Line 25**	$000	**$2,088**	**$14,795**	**$0**	**$0**	**$699**	**$62,134**	**$0**
29.	**Total Indifference Amount (Unadjusted)**	**Line 27 - Line 28**	$000	**($968)**	**($9,461)**	**($5)**	**$4**	**($7)**	**($31,290)**	**$0**
30.	**DWR Revenue Requirement**		$000							
31.	**PCIA Minimum Retained REC Value Adjustment**	**Table 11-5 x (Line 15 - Line 11)**	$000						**($45,168)**	**($22,412)**
32.	**Adjusted Indifference Amount**	**Sum (Lines 29:31)**	$000	**($968)**	**($9,461)**	**($5)**	**$4**	**($7)**	**($76,458)**	**($22,412)**
33.	**Revenue Franchise Fees & Uncollectibles (RF&U)**	**Advice 4512-G/6373-E**	$000	**($10)**	**($102)**	**($0)**	**$0**	**($0)**	**($827)**	**($242)**
34.	**Adjusted Indifference Amount with RF&U**	**Line 32 + Line 33**	$000	**($979)**	**($9,564)**	**($5)**	**$4**	**($7)**	**($77,284)**	**($22,654)**
35.	**Cummulative Adjusted Indifference Amount with RF&U**		$000	**$1,131,783**	**$1,122,220**	**$1,122,215**	**$1,122,219**	**$1,122,212**	**$1,044,928**	**$1,022,274**

To comply with D. 18-10-019, OP 3 and subsequent direction from the CPUC's Energy Division, PG&E, in October 2018, submitted revisions to the confidential version of PG&E's uniform common spreadsheet template for calculation of the PCIA rates. Lines 1 through 35 of the above table reflects thos included in one of the worksheets of the template.