

Docket No.: A.23-06-001

Exhibit No.: CalCCA-04

Date: September 26, 2023

Sponsor/Witness: Eric Lee (SCE)

EXHIBIT CALCCA-04

**Select Passages of Prepared Testimony from A.23-05-012
(PG&E's 2024 ERRRA Forecast Case)**

September 26, 2023

Application: 23-05-
(U 39 E)
Exhibit No.:
Date: May 15, 2023
Witness(es): Various

PACIFIC GAS AND ELECTRIC COMPANY

**2024 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
 2024 ENERGY RESOURCE RECOVERY ACCOUNT AND GENERATION
 NON-BYPASSABLE CHARGES FORECAST AND GREENHOUSE GAS FORECAST
 REVENUE RETURN AND RECONCILIATION
 PREPARED TESTIMONY

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CHAPTER 9

**POWER CHARGE INDIFFERENCE ADJUSTMENT AND
ONGOING COMPETITION TRANSITION CHARGE**

PACIFIC GAS AND ELECTRIC COMPANY
CHAPTER 9
POWER CHARGE INDIFFERENCE ADJUSTMENT AND ONGOING
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1 **3. Renewable Energy Credits**

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

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

15 For 2024, as a result of the voluntary allocation and market offer
16 (VAMO) process ordered by D.21-05-030 and further described in Chapter 4
17 and above in this chapter, PG&E forecasts that its bundled customer Net
18 Physical RPS Position (i.e., for 2024, forecast 2024 RPS-eligible generation
19 less allocation and/or market offer activity) will be less than PG&E’s RPS
20 compliance target for 2024. As such, PG&E proposes an extension of the
21 minimum retained RPS methodology implemented and approved by the
22 Commission for 2023. That is, to assign remaining 2021 and 2022 RECs,
23 and available prior year RECs on a last-in, first-out basis to meet its bundled
24 customer 2024 RPS compliance target. As described below, PG&E’s
25 methodology for 2024 rate-setting is consistent with RPS compliance rules,
26 which permit excess generation from a current RPS compliance period to be
27 applied to PG&E’s bundled customer 2024 RPS annual deficit, and for any
28 further deficits to draw from prior year RPS excess procurement amounts.

29 **a. Minimum Retained Requirement Volume**

30 In D.20-02-047, addressing PG&E’s 2020 ERRRA Forecast
31 Application, the Commission established that the annual RPS target
32 quantities provided in D.11-12-020 for calculating the RPS compliance
33 period requirement served as appropriate minimum quantities for PG&E
34 to consider for its annual retained RPS volumes as part of the PABA

1 true-up.³³ PG&E was ordered to record an accounting entry to reduce
2 the PABA and increase the ERRA based on an estimate of PG&E's
3 2019 RPS shortfall. While D.11-12-020 established annual minimum
4 quantities applicable to the third RPS compliance period in effect at the
5 time D.20-02-047 was issued, D.19-06-023 established minimum
6 quantities for the current 2021-2024 compliance period.³⁴

7 Table 9-4 below shows both the total annual net RPS generation
8 volumes for the current RPS compliance period up through 2023 as well
9 as the applicable years from the prior compliance period needed in
10 order to meet the forecasted minimum retained RPS entry for 2024. In
11 PG&E's pre-2023 ERRA Forecast proceedings, PG&E's ERRA revenue
12 requirement was calculated to recover the full RPS market value
13 associated with PG&E's forecasted annual RPS generation volumes,
14 net of forecasted third party sales. Column G of Table 9-4 shows the
15 net physical RPS position for all pre-2023 years except that 2019
16 exceeded the minimum RPS requirement or annual RPS compliance
17 target. Accordingly, no adjustment entries were necessary for these
18 years.

19 Consistent with the methodology proposed and adopted in PG&E's
20 2023 ERRA Forecast proceeding, an adjustment entry was necessary
21 for 2023 due to the VAMO mechanism ordered by D.21-05-030 and
22 detailed in PG&E's testimony. PG&E forecasted that the impact from
23 the allocation/and or market offer of its DL share of the PCIA-eligible
24 portfolio would result in PG&E's 2023 net physical position being less
25 than its annual RPS target established in D.19-06-023. Given the
26 forecast deficit, the following sections describe the methodology PG&E
27 proposed and the Commission adopted for 2023 rate-setting and
28 PG&E's proposal for 2024 rate-setting to determine: (1) how many
29 additional RECs to apply for bundled customer RPS compliance as part

33 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.").

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

1 of the PCIA revenue requirement calculation; and (2) how the value of
2 those additional RECs utilized for bundled customer RPS compliance
3 will be allocated across PCIA vintages within the RPS compliance
4 period.³⁵

5 **1) 2023 Methodology**

6 Pursuant to Senate Bill (SB) 2 enacted in 2011, the legislature
7 established multi-year compliance periods for RPS compliance
8 beginning with 2011 through 2013.³⁶ The total quantity of
9 RPS-eligible procurement required for a compliance period is
10 referred to as the “procurement quantity requirement.” D.11-12-020,
11 approved by the Commission on December 1, 2011, set the RPS
12 procurement quantity requirements for the first three RPS
13 compliance periods, culminating in 2020. Pursuant to COL 6 in
14 D.11-12-020, retail sellers are not required to demonstrate a specific
15 quantity of procurement for any intervening year in a compliance
16 period. Rather, as stated in COL 7, retail sellers are required to
17 show compliance with the procurement quantity requirement for a
18 compliance period by procuring the cumulative quantity of
19 RPS-eligible resources required for that compliance period.³⁷ In
20 other words, regardless of shortfalls in any particular year or years
21 within a compliance period, retail sellers can demonstrate
22 compliance with the procurement quantity requirement by procuring
23 the cumulative quantity of RPS-eligible resources for that
24 compliance period during any time throughout that compliance
25 period. Therefore, should there be a shortfall in RPS-eligible

³⁵ PG&E’s methodology addresses the need for a tracking framework identified in D.20-02-047.

³⁶ 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.”

³⁷ 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 years 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.

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

4 The same RPS compliance period requirement methodology
5 was established for post-2020 RPS compliance periods by SB 100
6 enacted in 2018 and implemented by the Commission in
7 D.19-06-023. Like prior RPS compliance periods, an RPS
8 procurement shortfall in one year can first be satisfied by prior year
9 excess in the current compliance period. For 2023, PG&E can
10 apply 2021 and 2022 RECs, as both of those years fall in the fourth
11 compliance period spanning from 2021 through 2024.

12 Given the interdependence of RPS compliance between years
13 in a particular RPS compliance period, PG&E proposed the
14 following methodology to determine how many additional RECs
15 generated prior to 2023 within the fourth compliance period are
16 applied for bundled customer RPS compliance as part of the 2023
17 PCIA revenue requirement calculation. The methodology also
18 addressed how those RECs will be allocated across PCIA vintages
19 within the applicable RPS compliance period.

- 20 1) For a year in which there is a net shortfall and the remaining
21 surplus RPS balance from the prior year(s) within the applicable
22 RPS compliance period is greater than the ERRA year shortfall,
23 an accounting adjustment will be made only to those years.
- 24 2) The adjustment will be weighted across the applicable RPS
25 generation surplus years based on the remaining amount of
26 surplus available for each year.

27 The proposed allocation methodology for 2023 was consistent
28 with PG&E's 2021 and 2022 ERRA Forecast applications where the
29 ERRA revenue requirement included the full retained REC value of
30 the RPS generation less forecasted RPS Sales for each year.
31 Therefore, customers who were part of PG&E's bundled customer
32 base in each ERRA year were charged for all surplus RPS
33 generation (i.e., RPS generation which exceeds the imputed annual
34 compliance obligation and forecast sales). It is precisely those

1 customers that earlier procured surplus RPS generation that benefit
2 from an accounting adjustment for 2023 rate-setting.

3 **2) 2024 Methodology**

4 Following the methodology laid out above, the minimum
5 retained RPS entry for 2024 will first credit remaining excess RECs
6 from 2021 and 2022 before applying additional crediting to excess
7 RECs available from years before 2021. As noted above, PG&E
8 proposes to utilize a last-in first-out approach to meet these deficits.
9 PG&E recommends this approach for its simplicity and for its
10 consistency with RPS compliance rules allowing for any further
11 deficits to draw from prior year excess RPS procurement amounts.

12 The following sections present the implementation of this
13 methodology.

14 **3) Historical Initial Annual Net Renewables Portfolio Standard** 15 **Positions**

16 In order to determine how accounting adjustments will address
17 PG&E's forecast 2024 RPS deficit, PG&E must first establish how
18 much surplus RPS generation exists from the same compliance
19 period as well as the amounts of surplus RPS generation from
20 applicable years in the prior compliance period. To do so, a net
21 available RPS quantity for each applicable year must first be
22 calculated. This information is presented in Table 9-4, with column
23 A showing the delivery year, which also represents the applicable
24 ERRA Forecast year. Columns B, C, and D include the net physical
25 RPS position, unsold RPS volumes, and PG&E bundled sales,
26 respectively. RPS generation for 2023 includes both actual RPS
27 generation as well as forecasted data. Forecasted RPS generation
28 data for part of 2023 and all of 2024 is calculated using PG&E's
29 RPS stochastic forecasting model.³⁸ More details on this model
30 and how generation forecasts are calculated can be found below.

³⁸ Consistent with the RPS Stochastic Model used in PG&E's Final 2022 RPS Procurement Plan.

**TABLE 9-4
ANNUAL AVAILABLE RPS GENERATION**

Line No.	(A) Delivery Year	(B) Net Physical RPS Position ^(b) (MWh)	(C) Unsold RPS	(D) Bundled Sales (MWh)	(E) Annual RPS Compliance Target (%)	(F) = (D * E) Annual RPS Compliance Target (MWh)	(G) = (B - C - F) Net Available Compliance Period RPS Generation (MWh)
1	2018	18,934,717	–	48,832,111	29%	14,161,312	4,773,405
2	2019	10,444,565	–	35,956,100	31%	11,146,391	(701,826)
3	2020	12,271,881	–	35,838,070	33%	11,826,563	445,318
4	2021	17,250,635	–	33,149,379	36%	11,850,903	5,399,732
5	2022 ^(a)	13,737,610	–	28,776,746	39%	11,079,047	2,658,563
6	2023	10,003,832	4,090,485	30,544,937	41%	12,599,786	(6,686,439)
7	2024	7,269,735	–	28,831,236	44%	12,685,744	(5,416,009)

(a) Values for delivery year 2022 will be updated during PG&E's 2024 ERRR Forecast Application Fall Update based on PG&E's final 2022 RPS compliance report.

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

1 Columns E and F include the annual RPS compliance
 2 target percentages and quantities respectively that need to be met
 3 by PG&E. The quantities included in Table 9-4 reflect rules and
 4 requirement quantities applicable to the current RPS compliance
 5 period, as laid out in D.19-06-023.³⁹ In D.19-06-023, the
 6 Commission maintained RPS target quantities that are ultimately
 7 based on a straight-line trend to reach each compliance period's
 8 RPS target.

9 With data captured annually for recorded RPS generation,
 10 Bundled Sales and RPS requirement targets, the net available RPS
 11 compliance period generation quantity in each year can be
 12 calculated by subtracting Columns C and F from Column B. The
 13 next section details how the net available RPS compliance period
 14 generation quantities from Table 9-4 have been adjusted for any
 15 prior minimum retained RPS entries.

4) Historical Minimum Renewables Portfolio Standard Entries

16 As referenced above, the CPUC established the minimum
 17 retained RPS requirement in D.20-02-047, with 2019 being the first
 18

³⁹ D.12-06-038: Decision Setting Compliance Rules for the RPS Program.
https://docs.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/169704.pdf.

1 effective year of this requirement. In order to satisfy this
 2 requirement for 2019, PG&E recorded accounting entries crediting
 3 earlier PCIA vintages through PABA. For 2021 and 2022, no
 4 minimum retained RPS entries were necessary as PG&E's bundled
 5 RPS position exceeded the annual target in each of those years.
 6 For 2023, PG&E is recording accounting entries crediting PABA
 7 vintages 2021 and 2022 based on the CPUC approved methodology
 8 described above. Table 9-5 provides the adjusted net RPS position
 9 for each applicable year in Column D by accounting for all prior year
 10 minimum RPS entries (Column C).

**TABLE 9-5
 HISTORICAL 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 ^(a)	(D) Adjusted Net RPS Position
1	2018	4,773,405	–	4,773,405
2	2019	(701,826)	701,826	–
3	2020	445,318	–	445,318
4	2021	5,399,732	(4,480,473)	919,258
5	2022	2,658,563	(2,205,966)	452,598
6	2023	(6,686,439)	6,686,439	–
7	Total	5,888,753	701,826	6,590,579

(a) Minimum retained RPS entry for 2019 credited pre-2018 PCIA vintages.

11 The adjusted net RPS position then serves as the basis for
 12 weighting the forecasted minimum RPS entry for 2024 presented
 13 below.

**5) Determination of Additional Retained Renewable Energy
 Credits for 2024**

16 Following the methodology laid out above, the minimum
 17 retained RPS entry for 2024 will first credit 2021 and 2022 based on
 18 their respective Adjusted Net RPS Position volumes and debit

1 ERRA for 1,371,856 MWh (919,258 MWh plus 452,598 MWh).
 2 Since there remains a net RPS deficit for 2024 after accounting for
 3 the 2021 and 2022 volumes, additional crediting is required to utilize
 4 earlier years' RECs with available Adjusted Net RPS Position
 5 volumes. As noted above, PG&E proposes to utilize a last-in
 6 first-out approach to meet these deficits. PG&E recommends this
 7 approach for its simplicity and for its consistency with RPS
 8 compliance rules allowing for any further deficits to draw from prior
 9 year RPS excess procurement amounts. The results of the
 10 forecasted entries are shown in Table 9-6 below.

**TABLE 9-6
 2024 MINIMUM RETAINED RPS ENTRY**

Line No.	(A) Delivery Year	(B) Pre-2024 Adjusted Net RPS Position	(C) Minimum 2024 Entry	(D) = (B + C) Post-2024 Adjusted Net RPS Position
1	2018	4,773,405	(3,598,835)	1,174,570
2	2019	-	-	-
3	2020	445,318	(445,318)	-
4	2021	919,258	(919,258)	-
5	2022	452,598	(452,598)	-
6	2023	-	-	-
7	2024	(5,416,009)	5,416,009	-
8	Total	1,174,570	-	1,174,570

11 PG&E will update the forecasted 2024 minimum retained RPS
 12 entry in its Fall Update based on updated portfolio forecast
 13 assumptions.⁴⁰ The entries associated with the 2024 minimum
 14 retained RPS will be true-ed up through the applicable balancing
 15 accounts and presented as part of PG&E's 2024 ERRA Compliance
 16 Review Application.

⁴⁰ PG&E's Fall Update may also be impacted by any changes that may arise as a result of a PCIA rulemaking regarding Minimum Retained RPS.

**TABLE 9-8
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							
			UOG Legacy	2009	2010	2011	2012	2013	2014	2015
1.	CRS Eligible Portfolio Costs (\$000)	\$1,199	\$1,885,293	\$1,894,250	\$463,257	\$139,471	\$168,258	\$60,947	\$6,622	\$12,371
2.	CRS Eligible Non-Renewable Supply at Generation Meter (GWh)	0	24,806	13,576	1,290	754	1,115	547	51	118
3.	CRS Eligible Renewable Supply at Generation Meter (GWh)	13	310	2,673	1,898	615	716	436	56	79
4.	CRS Eligible Total Net Qualifying Capacity (MW)									
5.	CRS Eligible System NQC (System only, No flex or local)	1	1,118	136	29	16	35	11	1	2
6.	CRS Eligible Local NQC - PG&E (System and local, with or without flex)	0	1,904	885	91	31	209	3	1	1
7.	CRS Eligible Local NQC - SCE (System and local, with or without flex)	0	0	0	22	0	1	0	1	4
8.	CRS Eligible Flexible NQC (System and flex only, No local)	0	368	920	0	0	0	0	0	0

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 9-8
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
(CONTINUED)**

Line No.		UOG Legacy and Vintaged PCIA Portfolio							IOU Total Portfolio	
		2016	2017	2018	2019	2020	2021	2022		2023
1.	CRS Eligible Portfolio Costs (\$000)	\$2,469	\$11,786	(\$0)	\$46,268	\$8	\$84,589	\$0	\$403	\$4,985,518
2.	CRS Eligible Non-Renewable Supply at Generation Meter (GWh)	21	95	0	0	0	0	0	0	44,005
3.	CRS Eligible Renewable Supply at Generation Meter (GWh)	26	115	0	0	0	70	0	11	7,130
4.	CRS Eligible Total Net Qualifying Capacity (MW)	0	3	0	0	0	3	0	2	1,470
5.	CRS Eligible System NQC (System only, No flex or local)	1	82	0	401	0	2	0	0	3,846
6.	CRS Eligible Local NQC - PG&E (System and local, with or without flex)	0	0	0	119	0	0	0	0	147
7.	CRS Eligible Local NQC - SCE (System and local, with or without flex)	0	0	0	338	0	2,392	0	0	4,018
8.	CRS Eligible Flexible NQC (System and flex only, No local)									

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 9-9
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 4-1	
2.	Off Peak Energy Index (\$/MWh)	Table 4-1	
3.	On Peak Load Weight (%)	2022 Recorded Bundled Load - On Peak Hours	58.4%
4.	Off Peak Load Weight (%)	2022 Recorded Bundled Load - Off Peak Hours	41.6%
5.	Load Weighted Average Price (\$/MWh)	Line 1 x Line 3 + Line 2 x Line 4	
6.	Green/RPS Adder (\$/MWh)	2023 authorized Benchmark	\$12.63
7.	Green Benchmark (\$/MWh)	Line 6 + Line 5	
8.	System RA Benchmark (\$/kW-Year)	2023 authorized Benchamrk (\$7.39 kW-Month x 12)	\$88.68
9.	Local RA Benchmark (\$/kW-Year) - PG&E	2023 authorized Benchamrk (\$6.93 kW-Month x 12)	\$83.16
10.	Local RA Benchmark (\$/kW-Year) - SCE	2024 authorized Benchamrk (\$6.74 kW-Month x 12)	\$80.88
11.	Flexible RA Benchmark (\$/kW-Year)	2023 authorized Benchamrk (\$7.15 kW-Month x 12)	\$85.80
12.	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 9-10
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 9-8, Line 1	\$000	208,328	1,199	1,885,293	1,894,250	463,257	139,471	168,258	60,947	6,622	12,371
2.	CRS Eligible Non-Renewable Supply at Generation Meter	Table 9-8, Line 2	GWh	1,633	0	24,806	13,576	1,290	754	1,115	547	51	118
3.	CRS Eligible Renewable Supply at Generation Meter	Table 9-8, Line 3	GWh	112	13	310	2,673	1,898	615	716	436	56	79
4.	CRS Eligible System NQC	Table 9-8, Line 5	MW	113	1	1,118	136	29	16	35	11	1	2
5.	CRS Eligible Local NQC - PG&E	Table 9-8, Line 6	MW	236	0	1,904	885	91	31	209	3	1	1
6.	CRS Eligible Local NQC - SCE	Table 9-8, Line 7	MW	0	0	0	0	22	0	1	0	1	4
7.	CRS Eligible Flexible NQC	Table 9-8, Line 8	MW	0	0	368	920	0	0	0	0	0	0
8.	Portfolio Unit Cost	Line 1 / (Line 2 + Line 3)	\$/MWh	\$119	\$90	\$75	\$117	\$145	\$102	\$92	\$62	\$62	\$63
Market Value of Portfolio													
Market Value of Brown Portfolio													
11.	Non-Renewable Energy	Line 2	GWh	1,633	0	24,806	13,576	1,290	754	1,115	547	51	118
12.	Weighted Average Brown Benchmark	Table 9-9, Line 5	\$/MWh										
13.	Market Value of Brown Portfolio	Line 10 x Line 11	\$000										
Market Value of Green Portfolio													
15.	Renewable Energy	Line 3	GWh	112	13	310	2,673	1,898	615	716	436	56	79
16.	Weighted Average Green Benchmark	Table 9-9, Line 7	\$/MWh										
17.	Market Value of Green Portfolio	Line 14 x Line 15	\$000										
Capacity Adder													
19.	Average Monthly System NQC	Line 4	MW	113	1	1,118	136	29	16	35	11	1	2
20.	System RA Benchmark	Table 9-9, Line 8	\$/kW-Year	\$88.68	\$88.68	\$88.68	\$88.68	\$88.68	\$88.68	\$88.68	\$88.68	\$88.68	\$88.68
21.	Average Monthly Local Area NQC (PG&E)	Line 5	MW	236	0	1,904	885	91	31	209	3	1	1
22.	Local RA Benchmark (PG&E)	Table 9-9, Line 9	\$/kW-Year	\$83.16	\$83.16	\$83.16	\$83.16	\$83.16	\$83.16	\$83.16	\$83.16	\$83.16	\$83.16
23.	Average Monthly Local Area NQC (SCE)	Line 6	MW	0	0	0	0	22	0	1	0	1	4
24.	Local RA Benchmark (SCE)	Table 9-9, Line 10	\$/kW-Year	\$80.88	\$80.88	\$80.88	\$80.88	\$80.88	\$80.88	\$80.88	\$80.88	\$80.88	\$80.88
25.	Average Monthly Flexible NQC	Line 7	MW	0	0	368	920	0	0	0	0	0	0
26.	Flexible RA Benchmark	Table 9-9, Line 11	\$/kW-Year	\$85.80	\$85.80	\$85.80	\$85.80	\$85.80	\$85.80	\$85.80	\$85.80	\$85.80	\$85.80
27.	Market Value of Capacity	Sum (Lines 19x20,21x22,23x24,25x26)	\$000	\$29,687	\$95	\$288,999	\$164,645	\$11,876	\$4,012	\$20,566	\$1,228	\$190	\$542
28.	Portfolio Market Value	Line 12 + Line 16 + Line 27	\$000	\$178,090	\$1,380	\$2,408,921	\$1,567,356	\$304,401	\$127,123	\$183,941	\$89,526	\$9,906	\$18,102
Indifference Amount													
30.	Portfolio Total Cost	Line 1	\$000	\$208,328	\$1,199	\$1,885,293	\$1,894,250	\$463,257	\$139,471	\$168,258	\$60,947	\$6,622	\$12,371
31.	Portfolio Market Value	Line 28	\$000	\$178,090	\$1,380	\$2,408,921	\$1,567,356	\$304,401	\$127,123	\$183,941	\$89,526	\$9,906	\$18,102
32.	Total Indifference Amount (Unadjusted)	Line 30 - Line 31	\$000	\$30,239	(\$182)	(\$523,629)	\$326,894	\$158,856	\$12,347	(\$15,683)	(\$28,578)	(\$3,284)	(\$5,731)
33.	DWR Revenue Requirement		\$000										
34.	PCIA Minimum Retained REC Value Adjustment		\$000										
35.	Adjusted Indifference Amount	Sum (Lines 32:34)	\$000	\$30,239	(\$182)	(\$523,629)	\$326,894	\$158,856	\$12,347	(\$15,683)	(\$28,578)	(\$3,284)	(\$5,731)
36.	Revenue Franchise Fees & Uncollectibles (RF&U)	Advice 4512-G/6373-E	\$000	\$327	(\$2)	(\$5,661)	\$3,534	\$1,717	\$133	(\$170)	(\$309)	(\$36)	(\$62)
37.	Adjusted Indifference Amount with RF&U	Line 35 + Line 36	\$000	\$30,565	(\$184)	(\$529,290)	\$330,428	\$160,573	\$12,481	(\$15,852)	(\$28,887)	(\$3,319)	(\$5,793)
38.	Cummulative Adjusted Indifference Amount with RF&U		\$000	\$30,565	(\$184)	(\$529,290)	(\$198,862)	(\$38,289)	(\$25,808)	(\$41,660)	(\$70,547)	(\$73,867)	(\$79,660)

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Totals may not add due to rounding

**TABLE 9-10
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	2023	
Cost of Portfolio												
1.	Portfolio Total Cost	Table 9-8, Line 1	\$000	2,469	11,786	(0)	46,268	8	84,589	0	403	
2.	CRS Eligible Non-Renewable Supply at Generation Meter	Table 9-8, Line 2	GWh	21	95	0	0	0	0	0	0	
3.	CRS Eligible Renewable Supply at Generation Meter	Table 9-8, Line 3	GWh	26	115	0	0	0	70	0	11	
4.	CRS Eligible System NQC	Table 9-8, Line 5	MW	0	3	0	0	0	3	0	2	
5.	CRS Eligible Local NQC - PG&E	Table 9-8, Line 6	MW	1	82	0	401	0	2	0	0	
6.	CRS Eligible Local NQC - SCE	Table 9-8, Line 7	MW	0	0	0	119	0	0	0	0	
7.	CRS Eligible Flexible NQC	Table 9-8, Line 8	MW	0	0	0	338	0	2,392	0	0	
8.	Portfolio Unit Cost	Line 1 / (Line 2 + Line 3)	\$/MWh	\$53	\$56	\$0	\$0	\$0	\$1,206	\$0	\$35	
Market Value of Portfolio												
10.	Market Value of Brown Portfolio											
11.	Non-Renewable Energy	Line 2	GWh	21	95	0	0	0	0	0	0	
12.	Weighted Average Brown Benchmark	Table 9-9, Line 5	\$/MWh									
13.	Market Value of Brown Portfolio	Line 10 x Line 11	\$000									
14.	Market Value of Green Portfolio											
15.	Renewable Energy	Line 3	GWh	26	115	0	0	0	70	0	11	
16.	Weighted Average Green Benchmark	Table 9-9, Line 7	\$/MWh									
17.	Market Value of Green Portfolio	Line 14 x Line 15	\$000									
Capacity Adder												
18.	Average Monthly System NQC	Line 4	MW	0	3	0	0	0	3	0	2	
19.	System RA Benchmark	Table 9-9, Line 8	\$/kW-Year	\$88.68	\$88.68	\$88.68	\$88.68	\$88.68	\$88.68	\$88.68	\$88.68	
20.												
21.	Average Monthly Local Area NQC (PG&E)	Line 5	MW	1	82	0	401	0	2	0	0	
22.	Local RA Benchmark (PG&E)	Table 9-9, Line 9	\$/kW-Year	\$83.16	\$83.16	\$83.16	\$83.16	\$83.16	\$83.16	\$83.16	\$83.16	
23.	Average Monthly Local Area NQC (SCE)	Line 6	MW	0	0	0	119	0	0	0	0	
24.	Local RA Benchmark (SCE)	Table 9-9, Line 10	\$/kW-Year	\$80.88	\$80.88	\$80.88	\$80.88	\$80.88	\$80.88	\$80.88	\$80.88	
25.	Average Monthly Flexible NQC	Line 7	MW	0	0	0	338	0	2,392	0	0	
26.	Flexible RA Benchmark	Table 9-9, Line 11	\$/kW-Year	\$85.80	\$85.80	\$85.80	\$85.80	\$85.80	\$85.80	\$85.80	\$85.80	
27.	Market Value of Capacity	Sum (Lines 19x20,21x22,23x24,25x26)	\$000	\$98	\$7,150	\$0	\$71,941	\$0	\$205,653	\$0	\$183	
28.	Portfolio Market Value	Line 12 + Line 16 + Line 27	\$000	\$4,369	\$26,253	\$0	\$71,941	\$0	\$212,449	\$0	\$1,288	
Indifference Amount												
29.	Portfolio Total Cost	Line 1	\$000	\$2,469	\$11,786	(\$0)	\$46,268	\$8	\$84,589	\$0	\$403	
30.	Portfolio Market Value	Line 28	\$000	\$4,369	\$26,253	\$0	\$71,941	\$0	\$212,449	\$0	\$1,288	
31.	Total Indifference Amount (Unadjusted)	Line 30 - Line 31	\$000	(\$1,900)	(\$14,467)	(\$0)	(\$25,674)	\$8	(\$127,860)	\$0	(\$885)	
32.												
33.	DWR Revenue Requirement		\$000									
34.	PCIA Minimum Retained REC Value Adjustment		\$000									
35.	Adjusted Indifference Amount	Sum (Lines 32:34)	\$000	(\$1,900)	(\$14,467)	(\$45,453)	(\$25,674)	(\$5,616)	(\$139,470)	(\$5,716)	(\$885)	
36.	Revenue Franchise Fees & Uncollectibles (RF&U)	Advice 4512-G/6373-E	\$000	(\$21)	(\$156)	(\$491)	(\$278)	(\$61)	(\$1,508)	(\$62)	(\$10)	
37.	Adjusted Indifference Amount with RF&U	Line 35 + Line 36	\$000	(\$1,921)	(\$14,623)	(\$45,945)	(\$25,951)	(\$5,677)	(\$140,978)	(\$5,778)	(\$895)	
38.	Cummulative Adjusted Indifference Amount with RF&U		\$000	(\$81,581)	(\$96,204)	(\$142,149)	(\$168,100)	(\$173,777)	(\$314,755)	(\$320,533)	(\$321,428)	

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